BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 050078-EI

In the Matter of

PETITION FOR RATE INCREASE BY
PROGRESS ENERGY FLORIDA, INC.
_______________________________/

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VOLUME 2

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PROCEEDINGS: TECHNICAL HEARING

BEFORE: CHAIRMAN BRAULIO L. BAEZ
COMMISSIONER J. TERRY DEASON
COMMISSIONER RUDOLPH "RUDY" BRADLEY
COMMISSIONER LISA POLAK EDGAR

DATE: Wednesday, September 7, 2005

TIME: Commenced at 9:30 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.
(No exhibits in this volume.)		

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

DIRECT TESTIMONY OF
H. WILLIAM HABERMEYER, JR.

I. Introduction and Background.

Q. Please state your name and business address.

A. My name is H. William Habermeyer, Jr. My business address is Progress Energy Florida, Inc. ("Progress Energy Florida" or the "Company"), 100 Central Avenue, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I serve as the Company's President and Chief Executive Officer. In this role, I have overall responsibility for the operations of Progress Energy Florida.

Q. Please describe your educational background and professional experience.

A. Please see Exhibit No. ___ (HWH-1) to my testimony.

II. Purpose and Summary of Testimony.

Q. What is the purpose of your direct testimony?

A. I will discuss the successful combination of two strong, Southeastern electric utilities into a stronger, better managed, and more efficient utility. I will provide an overview of our accomplishments over the last three years as we have improved in nearly every area of our business and have achieved top quartile performance in most key areas. I will further describe our goals for the future, the challenges that we face, and the additional elements necessary to put our plans into action.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. ___ (HWH-1), my current resume.
- Exhibit No. ___ (HWH-2), a comparison of PEF price with other consumer goods and services.

These exhibits are true and accurate.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements (MFRs)?

A. Yes, I sponsor or co-sponsor Schedule F-9. This is true and correct, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. Following completion of the merger, our goal was to become a world-class utility in the areas of reliability, energy supply, and customer service. To make significant progress toward this goal, we established our Commitment to Excellence program that defined specific objectives in the areas of employee satisfaction, safety, price, customer service, reliability, and generation adequacy over the three-year period between 2002 and 2004. I am proud to report that we substantially achieved each of our objectives, fulfilling the Commitment to Excellence program. In addition, we have strengthened our culture of excellence that will ensure continued improvements in meeting the growing and changing needs of our customers and our communities.

We have accomplished this without an increase in our base rates since 1993 and, in fact, with substantially lower base rates over the last three years, even though our price decreases are at odds with inflation in the rest of the economy. We cannot continue this trend forever, rather we must seek an increase in base rates to support our future plans.

We intend to build on the momentum we have developed through our Commitment to Excellence program. We will continue to meet our customers' increasing demands for more and more reliable energy through additional generation resources and system improvements while preserving our commitment to conservation and the environment. We also need to replenish and increase our storm reserve in light of the harsh lessons learned from the 2004 hurricane season in order to be better prepared for future hurricane seasons. We have in place a strong management team and the processes to ensure that we will achieve these objectives. We need, however, an increase in base rates to ensure that we can execute our plan and provide our customers with the level of service they have come to expect from us.

III. Our Performance Improvements.

Q. What did the merger achieve?

A. We have been transformed by the merger into a stronger, more efficient utility. Through our merger, we were able to combine various operational and management functions into a more streamlined and efficient scheme. We were also able to consolidate and eliminate redundant programs and identify and implement best practices, significantly reducing our costs. Some of these efforts and the resulting benefits will be explained more fully by other witnesses in this proceeding. The fact that we have become a more efficient utility is evident, however, in our improvements in performance with significantly lower rates over the last three years. These results demonstrate that the benefits of better performance and cost savings were achieved and that the merger was a success.

Q. What improvements have you made since the merger?

A. First and foremost, we've improved our performance in several areas through successful completion of our Commitment to Excellence program. At the time of the merger, we realized we needed to improve safety and reliability, lower our price to customers, increase the adequacy of our generation, and rally and focus our employees who had been distracted by the inevitable changes brought about by the merger. As a result, we developed our Commitment to Excellence program. The Commitment to Excellence program was a three year plan to achieve top quartile performance among our peer utilities in safety, rates, and customer service and to meet specific goals to improve reliability and increase our generation reserves. Additionally, our Commitment to Excellence program focused our employees on specific goals and objectives for the Company that created a culture of continuous improvement and improved employee morale.

Q. How was the Commitment to Excellence program a success?

A. We substantially met or exceeded each of the objectives of the Commitment to Excellence program. Other witnesses will explain in greater detail the specific projects and results achieved, however, we did see improvements each year of the program and in the end we met our objective of improving in each area that we identified and targeted for improvement.

We focused our efforts inside the Company and improved our employee safety by 51% over three years, moving to the brink of top quartile performance among our peer utilities based on most current benchmarks. We also improved employee satisfaction dramatically from the beginning of the program to the end of the program. This has resulted in a significant improvement in employee morale and has created the foundation for further operational improvements to the business.

We also turned our focus on our customers by improving our service and increasing our investment in our energy delivery system to improve our reliability of service. We met and actually exceeded our "SAIDI 80" goal by 2004, by reducing our SAIDI from 100.6 in 2000 to 77 in 2004, demonstrating that our increased investment in energy delivery paid off with greater reliability of service. In fact, our petition to exclude customer interruption minutes for recognized reasons, which is currently before the Florida Public Service Commission, would, if approved, further reduce this figure to 74.6 minutes. At the same time we were improving reliability, we reduced our residential base rates by 9.25% (as much as 16% for the typical 1,000 Kwh) as a result of the settlement of the last base rate proceeding, moving us into the top quartile of Florida electric utilities in providing low cost electric service by the end of 2004. And, our customer service performance, as measured by the JD Power

& Associates 2004 Electric Utility Residential Customer Satisfaction Study, improved from the third quartile at the beginning of the program to the first quartile by the end of the program in 2004.

Finally, we have improved the quantity and quality of our power supply reserves. We met our commitment to a 20% reserve margin in December, 2003 with the addition of the Hines 2 unit to our generation fleet, a full six months earlier than required. We have also improved the quality of these reserves by increasing the component that is comprised of actual hard assets as opposed to demand side management resources.

Q. Has the Company maintained or added to improvements in other areas besides the Commitment to Excellence program?

A. Yes, it has. We have maintained a commitment to operational excellence at our nuclear unit, Crystal River Unit 3 ("CR3"), that began before the merger and enhanced our operational performance. We have achieved steadily increasing levels of output at CR3 over the past several years and achieved an all-time station output record in 2004. This is especially important in an era of ever increasing fuel prices because our nuclear unit is the most cost efficient unit in our fleet. These improvements have helped us to mitigate the impact of rising fuel prices, especially oil and gas prices.

We have further increased the commercial availability of our steam generation by over 10% from 2000 to 2003, and substantially maintained that performance during 2004. The greater the availability of our existing fleet the longer we can defer the need for new generation. Also, we continue to maintain the most diverse fuel mix among the Florida investor owned utilities. Maintaining greater diversity in our fuel mix is another way we mitigate the effects of increases in prices among the various fuels we use to operate our generation resources.

We have also maintained our commitment to assist customers to use energy more efficiently. The Company has been a recognized leader in energy conservation and efficiency since 1981. Over the years the Company's energy efficiency programs have eliminated the need for 17 peaking power plants that otherwise would have been built. In addition, these programs have saved enough energy to power the City of St. Petersburg for about three years. We remain committed to maintaining and further developing our energy efficiency and conservation programs for our customers.

Q. What about the environment, does the Company have the same level of commitment to improvement of the environment?

A. Yes, it does. For example, improving air quality is one of our highest environmental priorities. We use innovative technologies to reduce, avoid, offset, or sequester emissions as much as possible. The energy savings mentioned above produce corresponding emissions savings equivalent to removing over 100,000 cars annually.

We also support alternative energy use. In Central Florida, we have partnered with the Florida Department of Environmental Protection and other companies in a pilot program in the development of fuel cell vehicles. As a result, we will be using hydrogen-fueled cars at our operations centers for meter readers and our energy-efficiency counselors who meet with customers. We have further sponsored the use of photovoltaic systems for research and the study of alternative energy sources in the statewide SunSmart Schools Program and teamed up again with the Florida Department of Environmental Protection to develop a sustainable hydrogen generator and fuel cell for the Homosassa Springs State Wildlife Park.

We also partnered with the Florida Solar Energy Center at the University of Central Florida and Palm Harbor Homes on the Manufactured Housing Photovoltaic Pilot Project to increase the use of low-cost solar energy in manufactured housing. As a result of this effort, Florida Governor Jeb Bush named Progress Energy the winner of the Sustainable Florida Award in September 2003. This award honors outstanding contributions to Florida's long-term prosperity and environmental health.

These are just a few examples of our strong environmental record. Environmental responsibility is a core value of the Company. We have managed our environmental performance well and we are committed to excellence in our environmental practices and performance in the future.

Q. In what other ways do you believe the Company has excelled?

A. You only need to look back to our response during the 2004 hurricane season to see some of the benefits of our emphasis on identifying and implementing best practices. As a result of best practices we responded to the 2004 hurricane season with comprehensive storm plans representing the cumulative experience of both Progress Energy Florida and Progress Energy Carolinas. These plans, and our efforts at putting them into practice quickly and efficiently, allowed us to meet the challenges of restoring power during an unprecedented hurricane season where four back-to-back hurricanes impacted our customers in our service territory. The four hurricanes left an unprecedented number of customers without service at their peak, yet in every case we excelled in restoring service to those customers who could receive service, doing so in as little as two days for Hurricane Ivan and only up to nine days for Hurricane Charley, despite the fact that over 500,000 of our customers, or 1.25 million people, were left without service at the peak of that hurricane. Our employees worked tirelessly and with great dedication to prepare for, respond to, and recover from what turned out to be the worst hurricane season on record for the State of Florida. As a result of our hurricane response efforts, we were awarded the Edison Electric Institute ("EEI") Emergency Response Award.

I also want to point out that our dedication extends to our communities where we live and work. Being a strong corporate citizen is another core value of the Company. Through the Company and our employees, we look for and act upon ways to bring additional value to the communities in which we serve. Over the past several years, I believe we've been successful in building stronger relationships with our communities by increasingly partnering with them and working shoulder-to-shoulder to solve a variety of issues.

IV. <u>Our Vision and Needs for the Future</u>.

Q. What is the Company's plan for the future?

A. Our plan is to maintain and build upon the momentum we created through our Commitment to Excellence program and to maintain and improve upon all areas of our business. That is one reason the emphasis on a culture of continuous improvement was so important to our Commitment to Excellence program. We believe we have strengthened in our management and employees a sense of dedication to improvement that will influence all areas of our business. We have the management team and processes in place to achieve our objectives.

We will continue to look for ways to meet the expanding needs and expectations of our customers. For example, we will continue to automate solutions where possible, such as in meter reading, to improve customer service while controlling costs. Also, following up on our investment in upgrading our transmission and distribution systems and improving our restoration time following outages, we will emphasize ways to prevent faults from occurring on our system in the first place. In this way, we look to maintain and build upon the high level of reliability that we have achieved in the most efficient manner possible. These are just two examples of our plans to continue what we have achieved in terms of customer satisfaction and reliability. Other witnesses in this proceeding will develop these examples further and provide further detail to our plans in these areas.

We recognize that our customers' needs for energy continue to grow. As a result, we have added or will add two new, state-of-the-art, gas-fired combined cycle units, Hines 2 and Hines 3, to our generation resources in December 2003 and December 2005, respectively. Additionally, the Commission has approved the need for another gas-fired combined cycle unit, Hines 4, which is expected to achieve commercial operation in December 2007.

Q. Can you achieve your Company's plan of maintaining and building upon the improvements in your Company's operations at your current rates?

A. Unfortunately the answer is no, we cannot. The Company has not had an increase in base rates since 1993. In fact, the Company has substantially reduced its base rates over the last three years as a result of the settlement of our last base rate proceeding to a level that last existed in 1983. This recent rate reduction has saved Progress Energy Florida's customers more than half a billion dollars over the term of the rate stipulation. Increases in the total price paid by customers have been driven by escalating fuel costs, which have increased dramatically in the last two years, despite the Company's best efforts to mitigate the impact of the increases on its customers. Increases in the cost of fuel, of course, are largely outside the control of any utility, including the Company. As shown in Exhibit No. ____ (HWH-2), PEF's residential base rates and total rate have increased by only 16% and 34%, respectively, since February, 1983, the most recent month in which base rates were lower than today. By contrast, the consumer price index has increased by 95%, postage stamps have increased by 85%, and medical care has increased by 220% over the same time frame. These cost escalation figures demonstrate the Company's ability to hold base rates constant and even lower them by controlling its costs during a period of time when costs were otherwise rising in the rest of the economy.

The Company, therefore, has done a good job of reducing its operating costs following the merger, providing the customers many of the synergies that were identified in our last base rate proceeding. The Company was able to provide such significant improvements in service, reliability, and generation resources in the past three years while lowering base rates significantly only because of the synergies from the cost reductions following the merger and the Company's steadfast focus on cost control and operating efficiency.

The Company certainly will continue to focus on cost control and efficient operation of its business. One way the Company is doing this is with our recent corporate reorganization to once again streamline our operations where possible to reduce costs. This initiative is expected to generate O&M savings of almost $20 million in 2006 for the Company which has been included in our rate request. We will continue our efforts to control costs wherever possible to operate as efficiently as possible. In an era of ever increasing costs, however, we cannot continue to provide improving levels of service and reliability as well as expanding generation capacity at our current rates.

Q. What is the Company seeking in this proceeding?

A. The Company is asking the Commission to set base rates at a level consistent with the service and operational performance that customers expect. We believe an appropriate level will require an annual revenue requirements increase in base rates by approximately $206 million, beginning January 1, 2006. The requested increase will provide the Company with a reasonable opportunity to earn a fair return on its investment, including a 12.8% rate of return on the company's common equity. This increase in base rates is, in part, necessary to add capacity to meet the continued growth in customer demand. As I explained above, the Company has added new generation capacity in December 2003, will add new generation capacity in

December 2005, and will further add generation capacity in December 2007. We further expect to continue to invest in operational and reliability improvements that our customers have come to expect from us. And, significantly, we need to replenish and increase our storm reserve following the devastating impact of the catastrophic hurricane season of 2004. This hurricane season has taught us that severe storms can in fact reach regions far inside the state and cause significant damage. We need to replenish the storm reserve to plan for future hurricane seasons with those lessons in mind.

We believe this plan best represents a balance of cost versus the benefits that our customers have enjoyed and come to expect from their electric utility. In this way, our plan represents a true "win-win" situation for the utility and the customer.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF JEFF LYASH

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is Jeff Lyash. My business address is 100 Central Avenue, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida, Inc. ("Progress Energy" or the "Company"). I am Senior Vice President of Energy Delivery-Florida. In this role, I have direct responsibility for all energy distribution activities in Florida. In addition, I am responsible for setting priorities for and coordinating all aspects of energy transmission, distribution, and customer service to ensure that we deliver a quality product to our Florida customers.

Q. Please describe your educational background and professional experience.

A. I graduated with a bachelor's degree in mechanical engineering from Drexel University in 1984. Prior to joining Progress Energy, I worked with the Nuclear Regulatory Commission in a number of capacities. In 1993, I joined Progress Energy, and spent eight years at the Brunswick Nuclear Plant in Southport, North Carolina, ultimately becoming Director of Site Operations. In January 2002, I assumed the position of Vice President of Transmission/Energy Delivery in the Carolinas. On November 1, 2003, I was promoted to Senior Vice President of Energy Delivery-Florida, which is the position I currently hold.

Q. **What is the purpose of your direct testimony?**

A. I will summarize recent operational improvements in Energy Delivery realized primarily as a result of the merger and the Commitment to Excellence program. I will also explain our plans for the future as we continue striving to deliver the reliable service our customers expect at a competitive cost.

Q. **Please summarize your testimony.**

A. Energy Delivery has emerged from the merger a better managed, more efficient and stronger business. We have reinvested cost savings from the merger, such as those realized through the combination of functions and system platforms, into every area of our business, driving visible improvements for customers. We have emphasized and strengthened satisfaction among our employees and have built a culture increasingly focused on productivity and continuous improvement. We have invested in our employees and our systems and have achieved significant improvements in safety, reliability, and customer service. At the same time we have reduced our residential base rates by 9.25% (as much as sixteen (16) percent for the typical 1,000 Kwh customer.).

Our plan for the future is to maintain and improve upon the high quality service and reliability we currently provide our customers. We have the management teams and business processes in place to drive these results provided that we obtain the reasonable rates necessary to achieve them. We will continue to invest in our distribution, transmission, and customer service systems in a focused way that prioritizes programs delivering the greatest value at the most reasonable cost. We will also continue to look for ways to use new technology to provide our customers with the service they desire. Our customers' sophistication is growing, and as it does, they require more and more reliable power to meet their needs. We believe our plan represents the best way to meet these needs at a reasonable cost.

II. Overview of Energy Delivery.

Q. What is the function of Energy Delivery within Progress Energy Florida?

A. Energy Delivery is broadly responsible for all aspects of power delivery from the generation source to our customers' premise. This involves both the transmission and distribution delivery systems, including the management, operation and maintenance of, and capital improvements to, both systems. In addition, it involves the customer service functions that handle customer inquiries and provide information to our customers regarding their service. The Company's transmission system includes over 4,700 circuit miles of transmission lines, over 90 transmission substations, and the associated fixtures and equipment. Likewise, the Company's distribution system includes about 25,000 circuit miles, over 275 distribution substations, and the related fixtures and equipment. Within both systems we also have the vehicles, equipment, and linemen necessary for operation and maintenance. To handle customer inquiries and issues, we operate two state-of-the-art customer service centers in Clearwater and Lake Mary. With these facilities, the Company currently delivers power to about 1.5 million customers over 20,000 square miles in approximately 35 of the state's 67 counties.

Q. How would you describe the current status of Energy Delivery?

A. Energy Delivery has made significant management and operational improvements in the areas of transmission, distribution, and customer service and currently provides strong performance for customers. We have achieved these results in large part due to benefits flowing from the merger. For example, we have taken advantage of opportunities to eliminate duplicate functions, reduced costs to develop, operate, and maintain duplicate systems, expanded management and technical resources, and reinvested in our transmission, distribution, and customer service systems.

Q. What benefits did you obtain from the merger in Energy Delivery?

A. We've been able to reduce costs and improve performance through such efforts as the combination of duplicate functions and systems, the application of increased purchasing power, and the application of best practices. Examples of duplicate functions which have been combined include system engineering and information systems development, maintenance, and support. By driving ever-increasing consistency in our underlying systems and processes, we've been able to consolidate increasing amounts of support resources and have been able to realize the benefits of interoperability in the field. In times of crisis, this ability to shift personnel and technology resources from one jurisdiction to another with virtually no learning curve or down time becomes particularly beneficial. As an example, the implementation of a common radio system in both Florida and the Carolinas allowed us to transition additional crews almost seamlessly during the 2004 hurricanes. Similarly, the implementation of a common purchasing system in both jurisdictions allowed us to much more efficiently secure the extreme amount of material and equipment needed to respond to those hurricanes. Beyond this, adopting common platforms has enabled the faster and more trouble-free implementation of process changes. As an example, we improved our ETR (Estimated Restoration Times) procedures in 2002 and 2003 with a high level of success building on experience gained in the Carolinas a few years earlier. Our approximate doubling of purchasing power has provided significant benefits as well. Not only have we realized savings from combining the needs of both jurisdictions, but we've driven greater consistency in our engineering specifications, reduced the number of items stocked, and thereby reduced inventory levels. Finally, we've realized significant benefits from the application of best practices. One example of a best practice which has improved our Florida culture and operations is the expansion of performance measurement below the system level, right down to the regional and operating center levels. This has brought performance measurement closer to our employees' line of sight and has strengthened the link between their individual contributions and our success for customers. This cultural shift has been central to the progress we've made in many areas of our operations.

Q. What other improvements have been made in Energy Delivery?

A. We've made improvements in almost all areas of Energy Delivery. First, we've significantly improved employee morale. As you might expect, the uncertainty and change that comes with a merger had a negative effect on morale. We sought to renew our employees' focus on excellence and improve their morale by challenging them with the Commitment to Excellence. Our employees accepted the challenge, focused their efforts on the improvements in performance that we sought to obtain, and achieved them. As a result, morale and performance have improved and we have built a foundation for our future plans. We also renewed our commitment to safety as part of the Commitment to Excellence program. Our employees are our most valuable resource and making safety a priority reinforced their value to the Company. As a result of constant focus on improved safety, we reduced our injury rate by over 50%, improving to the brink of the top quartile in reported OSHA injury rates in 2004 among our peer utilities. In the area of reliability, we made a commitment to achieve a System Average Interruption Duration Index ("SAIDI") of 80 minutes by 2004 as part of our settlement of our last base rate proceeding. This represents a twenty (20) percent reduction from our 2000 SAIDI of 100.6 and was a major focus of our Commitment to Excellence program. I am very proud to say that we not only met but exceeded this level of performance. We improved our SAIDI each year and in 2004 achieved a SAIDI of 77, representing a twenty-three (23) percent reduction. We also improved in other industry distribution and transmission reliability measures. These improvements, and the specific programs or projects implemented to achieve them, are discussed in more detail in the testimony of David McDonald, Ray DeSouza, and Dale Oliver. In sum, however, our increasingly engaged and productive workforce, gains in efficiency and productivity brought about through the merger, and increased investment in our transmission and distribution systems paid off with significant improvements in our operations.

Q. **Have the improvements in Energy Delivery benefited your customers?**

A. Yes, they have. Customers have seen improvements in price, service, and reliability. As a result of the settlement of our last base rate proceeding we lowered our base residential rates to our customers by 9.25%, up to sixteen (16) percent for our typical 1,000 Kwh customer. Our typical residential price improved from thirty-third in 2001 to eleventh at the end of 2004 out of fifty-one electric utilities in the State of Florida. This base rate reduction for our customers is even more significant when you consider that we have not increased our base rates since 1993. We've also improved our customer service, moving from third quartile in 2001 to top quartile in 2004, based on our performance in the customer service component of the nationally recognized JD Power & Associates 2004 Electric Utility Residential Customer Satisfaction Study. In fact, our score places us among the top ten utilities in the country and first in the Southern Region. In terms of reliability, the improvements that we've made have provided our customers with a source of energy that is now within the top quartile of our peer utilities, based on most recent benchmarks.

Q. Is Energy Delivery positioned to continue to deliver quality service to customers at a reasonable cost?

A. Yes. Energy Delivery has the critical elements in place to provide increasingly efficient, high quality service at a reasonable cost. As I've described, we have strengthened our employee morale, productivity and culture as a foundation for continued improvement in the business. We've taken advantage of cost efficiencies and the application of best practices from our merger. We've enhanced our use of performance measurement metrics farther down into the organization and have linked these measures to our pay at all levels to ensure continued focus on results that matter for customers. In addition, we've increased our emphasis on benchmarking performance externally and internally to identify opportunities for improvement. We've also worked to improve our planning, prioritization, and budgeting processes, which will be described in further detail in the testimony of David McDonald, Ray DeSouza, and Dale Oliver. In combination, these elements have produced the improved operational performance that I've already summarized above as well as cost efficiencies throughout our business. For example, since 2002 we have achieved top quartile performance in the distribution cost to install new service (before CIAC reimbursement) and lowered our distribution O&M and capital maintenance cost from $120 per customer to $102 per customer, within the second quartile of our peer utilities based on most recent benchmarks. The positive momentum that we've achieved in so many areas of our business shows that these elements are working to produce results. We will continue to push for even better performance as we strive to provide excellent reliability and service for our customers at a competitive cost.

In fact, the Company is currently undertaking a complete review of its organizational structure in order to identify areas where further efficiencies can be achieved. This initiative, which will be implemented throughout 2005 and will include employee incentives for voluntary early retirement, is expected to produce almost $20 million in savings for Progress Energy Florida in 2006, including significant reductions in the areas of distribution, transmission, and customer service. These savings have been incorporated into our rate request.

Q. Can you provide us with an example of another way in which you have delivered reliable service to your customers?

A. Yes, I can. During 2004 our Company faced the most catastrophic hurricane season on record for the State of Florida. Despite this unprecedented storm season we were well prepared because we had already adopted as best practices aspects of the storm plans developed in the Carolinas by our sister company from more recent hurricane and major storm experience there. We continued to develop our storm plan and improve upon our response with each passing storm in 2004 as well. Having a sister utility in the Carolinas also provided us with the ability to quickly call upon additional resources as they were needed to respond to and recover from the series of 2004 hurricanes that impacted our service territory and our customers.

Hurricane Charley was a 145 mile per hour hurricane when it made landfall that left 502,000 of our customers without power at the peak of the hurricane. About 700 miles of transmission lines and 83 substations were put out of service in addition to the widespread damage caused by the hurricane. We implemented our storm plan 72 hours in advance of the hurricane making landfall, and coordinated the work of our own employees and over 5,000 outside line and tree crews, to respond to the hurricane and restore power as quickly and as safely as possible for the benefit of our customers and the public. From the moment the hurricane hit our service territory we were able to begin our restoration planning process so that as soon as the winds had died down to a safe level we had crews out addressing priority areas to restore service to the most customers possible and the most critical customers as soon as practicable. As a result of the implementation of our storm plan, we were able to restore power to all customers who were able to receive power within nine (9) days.

Our response to Hurricane Frances was a similar success story. This slow moving hurricane racked our service territory with 100 mile per hour winds for almost a full day. It also impacted our entire service territory, leaving 832,898 customers without service at its peak, and putting 1,131 miles of transmission line and 105 substations out of service. We coordinated the work of our internal employees and 4,600 outside line and tree crews and further improved upon our storm response efforts from the prior hurricane. For example, we learned that we needed more staging sites set up closer to the areas impacted with necessary materials and supplies for the restoration crews and we increased our use of helicopter cranes to quickly move needed material to work sites. These improvements, among others, in our storm response efforts were incorporated into our storm plan for Hurricane Frances. As a result of our storm preparation and response efforts, we were able to restore power to all customers who were able to receive power within six (6) days.

We have a similar story to tell for Hurricanes Ivan and Jeanne. Although Hurricane Ivan ultimately did not directly impact our service territory, we had to plan for the fact that it might have done so based on national weather service projections. In any event, we were in position to quickly restore power as a result of Hurricane Ivan to all customers who could receive power in two (2) days. Hurricane Jeanne was another major storm that did impact us directly, leaving 722,012 customers without power at its peak, and putting 853 miles of transmission line and 86 substations out of service. We again implemented our storm plan and coordinated the restoration work of 3,687 outside line and tree crews, in addition to our internal crews and employees, to restore power for all customers able to receive power within five (5) days.

The performance of our Customer Service Center during the hurricanes is also noteworthy. Our Customer Service Center employees and other employees who helped staff the phones and computers worked tirelessly during the course of the four hurricanes taking customer calls, identifying outages and reporting them to the managers responsible for the field crews, and keeping our customers informed on hurricane precautions and preparations before, during, and after the storms and our restoration efforts following the storms. These employees and contractors who manned the phones and computers handled 465,670 customer outage calls for Hurricane Charley, 929,228 customer outage calls for Hurricane Frances, 55,700 customer outage calls for Hurricane Ivan, and 741,920 customer outage calls for Hurricane Jeanne.

The impact of four successive hurricanes in 2004 was severe with widespread damage and disruption for our business and our customers. Despite the widespread damage and disruption of four hurricanes we were able to quickly and safely restore power following each storm. Our storm plan proved to be an effective tool in each hurricane and I believe our planning and restoration efforts during and following each storm were a success. We proved that we can meet our customers' and the public's need for an essential service in a time of crisis. Our ability to promptly and safely prepare for, respond to, and recover from these hurricanes has been recognized in our industry with the Edison Electric Institute "Emergency Response Award" in 2004.

III. Energy Delivery's Future Business Plan.

Q. What is the Energy Delivery plan for the future?

We plan to build on the momentum, raising the bar for our performance as we strive to continue improving service and reliability for our customers. I will provide an overview of our plans in distribution, transmission, and customer service, while other witnesses in this proceeding will provide more detail on our plans in each area. In every area, however, we remain committed to maintaining the gains we have made in safety and employee satisfaction. We believe that safety is significant not only because employees are our most important resource, but also because we believe that safety improvement forces the work practices and focus necessary for excellence in other areas of our business. As well, we've focused on measuring and improving employee satisfaction because we believe it translates directly into better performance and happier customers.

- **Distribution.** We've worked diligently over the past several years to improve our overall system reliability, as measured by SAIDI, to a level that is within the top quartile of our peer utilities based on most recent benchmarks. Now that we have achieved this level of performance, we believe that we can bring about the most significant improvements in customer satisfaction by maintaining our overall system reliability within its current range while we broaden our focus from the mitigation of outages to the improvement in power quality by preventing faults from occurring in the first place. In addition, now that we have our system average performance at favorable levels, we intend to focus additional attention on those areas that lag behind system average performance. We believe this balancing and broadening of priorities will provide the most valuable benefits for our customers at the lowest cost.

- **Transmission.** We have made significant gains in transmission reliability as a result of our investments in capital and O&M in the transmission system. We plan to continue to improve our reliability performance by improving the material condition of our system and modernizing equipment and designs. We will focus on improving the ability of our system to withstand the effects of adverse weather, such as lightning and wind, and will continue working to prevent faults due to contacts with animals. As in the past, we will take a balanced and prioritized approach to deliver the maximum reliability benefits at the least cost.
- **Customer Service.** Likewise, we plan to maintain top quartile customer service. In order to accomplish this, we will continue listening to our customers and better understanding their needs and wants. A major focus going forward will be on automation and technology to meet our customers' demands for more prompt service, more information, and more alternatives. Not only will additional automation improve cost effectiveness, but it will result in real benefits for customers. As an example, our mobile meter reading program, which will enable Progress Energy to read meters wirelessly by

driving past a home in a vehicle that includes a computer and radio receiver, will dramatically reduce our operating costs while at the same time improving accuracy, reducing the number of estimated bills, and providing a less-intrusive meter reading process for customers. Beyond this, the addition of more robust internet tools will give customers an easy and quick way to resolve an increasing variety of issues on their own schedule, whether in the middle of the day or night.

Q. What is the cost of your Energy Delivery plan and is it reasonable?

A. Our plan calls for continued investment in our distribution, transmission, and customer service operations at a level sufficient to deliver the service and reliability our customers expect. We propose total O&M expenditures of $126.1 million in distribution, $36.8 million in transmission, and $44.9 million in customer accounts, customer service and information, and sales expenses in 2006. We believe these costs are reasonable and represent the right balance of price and operational benefits for our customers. Improving service and reliability does have a price, since we cannot continue to drive such improvements for customers without additional investment in our transmission, distribution, and customer service operations. We have been diligent in our planning and budgeting to ensure that we are identifying the right priorities to achieve our objectives. We continue to benchmark our capital and O&M costs against the industry to make sure that we are working efficiently. Our 2006 budget for Energy Delivery represents the right balance of costs to achieve the benefits that our customers desire and demand.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF
E. MICHAEL WILLIAMS

I. Introduction.

Q. State you name, position, and business address.

A. My name is E. Michael Williams. I am Senior Vice President of the Power Operations Group for Progress Energy. My business address is P. O. Box 1551, Raleigh, North Carolina 27602.

Q. What are your duties and responsibilities?

A. The Power Operations Group is a major component of the Energy Supply business unit. Power Operations includes: Fossil Generation, System Planning and Operations, Combustion Turbine ("CT") Operations, and Technical Services and Construction. These operations total over 16,740 megawatts ("MW") of generating capacity located at 30 plant sites in the Carolinas and Florida.

In this position, I must maintain a balanced and effective program to provide the most economical power from Progress Energy's fossil, hydro, and combustion turbine facilities, while maintaining well-equipped plants, complying with environmental regulations, maintaining the highest possible safety record, protecting assets, and leading Progress Energy to top levels of operating performance.

My major job duties and responsibilities include: developing and implementing strategic and tactical plans to accomplish operating objectives; managing and controlling fuel and operating expenditures; overseeing hundreds of employees and hundreds of millions of dollars in assets and operating budgets; and providing a significant degree of leadership so as to lead, motivate, and influence a large workforce to achieve high operation performance levels.

Q. Please describe your educational background and work expertise.

A. I earned a Bachelor of Science degree in Nuclear Engineering from Texas A&M University in 1971. In 1982, I completed Louisiana State University's Executive Program. Then, in 1989, I graduated from Harvard Business School's Program for Management Development.

I have 33 years of power plant and production experience in various supervisory, managerial, and executive positions within the former Central and South West Corporation ("CSW") (now American Electric Power or AEP). I began my career in the electric utility industry at Southwestern Electric Power Company ("SWEPCO") a subsidiary of CSW, as a Staff Engineer in 1972. In 1974, I became a maintenance supervisor at SWEPCO's Lieberman Power Plant, a four-unit, gas-fired plant. I was moved to the Welsh Power Plant, a three-unit, coal-fired plant, as the Maintenance Superintendent in 1975. Then, in 1982, I became the Plant Superintendent at the H.W. Pirkey Power Plant, a single unit, lignite-fired plant. In 1988, I moved into the position of Manager of Production for SWEPCO and had responsibility for all SWEPCO plants. In 1989, I became a Division Manager. In this position, I was responsible for all transmission, distribution, marketing, and customer service activities with SWEPCO's Western Division, headquartered in Longview, Texas.

Then in 1992, I became the Vice President of Engineering and Production for Public Service Company of Oklahoma ("PSO"), another subsidiary of CSW. Shortly thereafter, in 1993 I became CSW's Vice President of Fossil Generation in Dallas, Texas. In this position, I was responsible for the operation and maintenance of 34 fossil power plants in 4 states, including 5,000 MW of coal units, 9,000 MW of gas/oil units, and 500 MW of peakers. I was responsible for over 1,300 employees (both union and non-union), and annual budgets of approximately $150 million in operation and maintenance ("O&M"), and $130 million in capital.

I joined Carolina Power & Light Company in June of 2000 as Senior Vice President of its Power Operations Group.

II. Purpose and Summary of Testimony.

Q. What is the purpose of your testimony?

A. I appear on behalf of Progress Energy Florida ("PEF" or the "Company") to support the reasonableness of its power operation costs reflected in the Company's Minimum Filing Requirements ("MFRs").

Q. Have you prepared any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits to my testimony:

- Exhibit No. ___ (EMW-1), a list of the MFR schedules I sponsor or co-sponsor.
- Exhibit No.___ (EMW-2), Graphs: Power Plant Performance – Florida Steam Equivalent Forced Outage Rate, Equivalent Availability, and Florida Simple Cycle CT Starting Reliability.
- Exhibit No.___ (EMW-3), Progress Energy Fossil Plant 2005 Dismantlement

Cost Study.

These exhibits are true and accurate.

Q. What schedules in PEF's MFRs do you sponsor?

A. I sponsor or co-sponsor the MFR schedules listed on Exhibit No. ___ (EMW-1). These schedules are true and correct, subject to their being updated in the course of this proceeding.

Q. Please summarize your testimony.

A. The Power Operations Group is committed to the highest standards for safety, environmental stewardship, corporate citizenship, and ethical conduct. PEF's forecasted capital and O&M expenses for power plant operations reflect its commitment to: (a) maintain a high degree of availability and reliability of its existing power plants at a reasonable cost; and (b) increase its generation supply by bringing into service new, cost effective, efficient, environmentally friendly, and operationally responsive combined cycle ("CC") units.

PEF has invested more than $110 million in its fossil steam, CT and CC power plants since 2002. We will spend an additional $100 million on improvements to our plants between 2005 and 2006. In addition to adding hard assets, we continue to operate our Florida fleet at the highest performance levels. Effective programs that identify, prioritize, and implement maintenance on these plants, including planned outages, are firmly in place. These have helped us minimize production costs. In addition, the Power Operations Group, in support of the corporate cost-management initiative, committed to effect organizational changes in 2005 that will reduce the need for O&M in 2006. This savings is estimated to be approximately $2.5 million for Power Operations in Florida. As a result, we have been able to hold our production costs down to a modest 3.7% compound annual growth rate for the period 2002 through 2006 (Refer to MFR Schedules C-6 and C-37). Included in these production costs are the O&M expenses associated with new CC generating capacity.

To meet the growing demand for power in Florida and to meet the Company's commitment to increase reserve margins with hard assets, we will have added more than 1,000 MW of highly efficient and cost effective power plant capacity over the period 2003 through 2005. Following a competitive bid process, we added a second state-of-the-art 500MW natural gas fired CC unit, Hines 2, at our Hines Energy Complex in Polk County in 2003. Similarly, we will complete the construction of a third 500MW CC unit, Hines 3, at that site by the end of 2005. These intermediate units have enhanced the flexibility of PEF's power generation system and added fuel diversification to the Company's fleet. The combined cost of these units will be approximately $450 million.

We have accomplished these results while achieving a 44% reduction in the number of injuries in the workplace since 2002.

Our objective going forward is to enhance the value and improve the reliability and cost effectiveness of our generation fleet. To accomplish this, we will continue to prudently invest in the availability and reliability of our generating assets.

III. Power Operations Since 2001.

Q. Please describe the performance of PEF's fossil power generating fleet since 2001.

A. Since 2001, we have continued the excellent operations of our Florida fossil generating fleet, both in terms of plant operations and production costs.

Fossil Steam Generation

In 2001, Power Operations undertook an aggressive program to improve the performance of steam assets in Florida. This first included the completion of a formal material condition assessment for each of the steam units. Fossil Operations used the results of these assessments to prioritize work on selected units.

Initially, we completed a number of maintenance projects on PEF's Crystal River Unit 4 in the spring of 2002. By the end of 2004, we had completed similar maintenance work on each of the four Crystal River fossil steam units. We undertook additional maintenance work at the Anclote, Bartow, and Suwannee plants during this period. Between 2002 and 2004, Fossil Operations invested approximately $96.5 million in those plants. The formal Florida steam performance improvement plan will be completed by the end of 2007. Between 2005 and 2007 we will invest an additional $26 million on the Florida steam units to fully implement the plan.

In addition to the investment in these plants, we enhanced programs to support continued superior plant performance and efficiency of operation. This included, among other initiatives, enhancements to work management, project initiation and management, project prioritization, and outage planning and implementation processes and procedures. Power Operations also made significant investment in training to ensure the success of these initiatives, including the enhancement of Operator and Maintenance Education Programs and the purchase of new Plant Simulators.

Q. Have your improvements resulted in positive operating performance?

A. Yes. Our improvements have yielded excellent results. For example, we have significantly decreased the duration of planned outages. While a major planned outage at Crystal River Unit 4 lasted 64 days in the spring of 2002, a similar outage in scope at Crystal River 5 later that fall lasted only 42 days. Crystal River 2 completed its 2003 planned outage in 45 days. This is a credit to the significant improvements made to outage planning, preparations, and implementation. The intense focus on work management has enabled our group to more efficiently perform activities in a timely and cost-effective manner while assuring proper attention is devoted to safety, environmental compliance, personnel, plant operation, and quality maintenance.

Our efforts have also resulted in improved operating performance of our steam units that beats the national average. Fossil steam equivalent availability for the Florida fleet was a high 86.9% in 2002. We nonetheless improved reliability to 89.7% by 2004 (90.2% when adjusted for hurricane related events). For comparison, the fossil steam equivalent availability average in 2003 for the industry was 85.8% (based on NERC data). See Exhibit No. ____ (EMW-2).

Fossil steam equivalent forced outage rate for the Florida fleet was 3.94% in 2002. For the year 2004, the equivalent forced outage rate improved to 2.73% (2.27% when adjusted for hurricane related events.) The industry average in 2003 was 5.04%. See Exhibit No. ____ (EMW-2).

PEF's investment in the Florida steam units is producing results. This is most evident in the above average performance and trends discussed above. It is consistent with the commitment to increase the availability and reliability of existing power plants at a reasonable cost. Fossil steam production costs have been held to a 2.5%

compound annual growth rate for the period 2002 through 2006. See Schedules C-6 and C-37. PEF will continue to invest in these plants to ensure historical performance levels and to meet new performance goals.

CT and CC Generation

PEF's combustion turbine and combined cycle fleet also continues to operate at extremely high levels of reliability. The Florida CT starting reliability in 2004 was 99.5%, continuing a trend of outstanding performance with annual starting reliabilities consistently above 99%. This compares to an average of 80% in the industry based on NERC data. See Exhibit No. ____ (EMW-2). The Florida CC units (Hines 1 & 2 and Tiger Bay) completed 2004 with an equivalent availability factor of 90.9%, well above the industry average of 79.8% (2003 NERC data). Hines 2 completed its first full year of commercial operation with an outstanding equivalent availability of 96.4%.

The capacity factors and number of starts associated with the units in this fleet should continue at the levels we have experienced during the last several years. Maintenance costs are largely driven by the number of starts and run time on these units. Therefore the costs over the next few years will be similar to previous years except for increases associated with the new combined cycle units at Hines. Approximately $2 million of incremental O&M costs are included in the 2006 budget associated with the first full year of commercial operation at Hines 3. Based on a dollar per KW installed basis, we have reduced spending since 2002. In 2002 we spent approximately $11.14/KW compared to $10.03/KW budgeted in 2006. Similar to the fossil steam division, robust work management, project initiation and management, and outage planning and execution have enabled this level of operating and financial performance. The Combustion Turbine Operations Department is committed to operating and maintaining these plants to the highest operating performance and efficiencies.

IV. **Budgeting.**

Q. Please describe your budgeting process and the measures you take to monitor and control costs.

A. Throughout the Company, including the functional areas under my management, we engage in rigorous cost evaluation and control for all capital expenditures and O&M costs. Our overall goal is to deliver top quartile reliability while maintaining top quartile cost control. Within each business unit, including Power Operations, O&M budgets and recommendations are developed by plant management based on targets keyed to historical spending and, increasingly, by metrics designed to drive functional units to top quartile performance levels. Capital budgets and project recommendations are developed by plant management and engineering staff based on equipment assessments and financial analysis of the individual capital projects. All capital and O&M proposals and requests must be supported and defended through a peer review process, subject to management approval. The monitoring of costs throughout each year is accomplished by monthly reporting of year-to-date budget versus actual spending, analysis of variances, and projected spending for the balance of the year.

V. **Power Plant Additions.**

Q. Please describe the power plant additions to PEF's fleet since 2002 and how they

were selected.

A. As noted above, PEF has added one 500MW CC plant, Hines 2, in 2003 and will add another 500MW CC plant, Hines 3, by the end of 2005. Progress Energy's System Planning & Operations Department made the decision to build the Hines 2 and Hines 3 plants through its integrated resource planning process and after a competitive bidding process. The integrated resource planning process essentially matches PEF's projected load growth with the most cost-effective power plant additions. The cost effectiveness of both plants was evaluated and affirmed by the Florida Public Service Commission (the "Commission") in the respective Hines 2 and Hines 3 need proceedings. (See Commission Orders PSC-01-0029-FOF-EI; PSC-03-0175-FOF-EI).

Q. What impact will these plant additions have on O&M going forward?

A. The base O&M costs for these units will be approximately $2 million per year per unit. As discussed earlier, the incremental costs included in the 2006 budget associated with the first full year of commercial operation at Hines 3 is approximately $2 million. Significant other costs will be incurred when the operation of these units necessitate outage maintenance activities to be planned. For example, Hines 2, which went into service in December 2003, will have a planned maintenance outage performed in 2006 at a cost of approximately $3.5 million. The actual operation of the units over time will dictate the timing and scope of the outages going forward.

VI. Fossil Dismantlement Cost Study.

Q. Please describe PEF's Fossil Dismantlement Cost Study filed with your testimony.

A. PEF commissioned Sargent & Lundy to prepare a fossil dismantlement study (the "Study") to determine the ultimate cost to dismantle and decommission the Company's fossil power plant fleet. Sargent & Lundy is a nationally recognized consulting firm with extensive expertise in preparing studies, such as the one commissioned by PEF. A copy of the Study is attached as Exhibit No. ____ (EMW-3). As the Study indicates, PEF will need to accrue $9,651,668 annually (retail) beginning in 2006 in order to assure that it will have enough funds to cover the costs of dismantlement and decommissioning of its fossil generating sites.

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY OF
DALE E. YOUNG

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is Dale E. Young. My business address is 15760 West Power Line Street, Crystal River, Florida 34428.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida ("PEF" or the "Company") in the capacity of Vice President – Crystal River Nuclear Plant.

Q. What are the duties and responsibilities of your position with PEF?

A. I am responsible for the safe and efficient operation of PEF's Crystal River Unit 3 nuclear power plant ("CR3").

Q. Please describe your educational background and professional experience.

A. From 1969 to 1977, I served as a Civil Engineering Officer in the United States Air Force, where I was responsible for a number of military construction projects. I attended college while in the service and received my Bachelor of Science degree in Electrical Engineering from the University of Missouri at Columbia in 1973. I later earned a Master's Degree in Business and Management from Webster College in 1977. Upon my discharge from the Air Force in 1977, I was employed as a Nuclear Plant Engineer with the Westinghouse Bettis Division, where I was responsible for operation and maintenance of a Naval Prototype plant used to train Navy nuclear operators. I moved to Union Electric Company in 1979 and was employed in Fulton, Missouri, at Union Electric's Callaway Plant, a 1200 MW pressurized water reactor plant. I held various engineering and management positions over the fifteen year period I worked at the Callaway Plant, including Shift Supervisor, Maintenance Manager, and Operations Manager. I held a Senior Nuclear Reactor's License from 1984 through 1994. In 1994, I was employed by Carolina Power and Light Company ("CP&L") at the Robinson Nuclear Plant in South Carolina. I was the Plant Manager from 1994 to 1997, when I was promoted to Director of Site Operations. I held that position until 1998, when I was promoted to Site Vice President, a position I held until December 2000. Since December 2000, I have been employed by Progress Energy as Vice President – Crystal River Nuclear Plant. I am a Registered Professional Engineer in the state of Missouri.

Q. What is the purpose of your direct testimony?

A. I appear on behalf of PEF to support the reasonableness of the Nuclear Generation portion of the Company's Capital and Operating and Maintenance ("O&M") expenses.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. __ (DEY-1), a list of the Minimum Filing Requirements (MFRs) Schedules I sponsor or co-sponsor.
- Exhibit No. __ (DEY-2), CR3 Non-Fuel O&M Two-Year Average Cost.

- Exhibit No. __ (DEY-3), CR3 Net Generation.
- Exhibit No. __ (DEY-4), PEF's 2005 Nuclear Decommissioning Study.
- Exhibit No. __ (DEY-5), Nuclear Regulatory Commission – 2005 Annual Assessment Letter.

These exhibits are true and accurate.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements (MFRs)?

A. Yes, I sponsor in whole or in part the MFR schedules listed on Exhibit No. ___ (DEY-1). These schedules are true and correct, subject to their being updated in the course of this proceeding.

Q. Please summarize your testimony.

A. The Crystal River Unit 3 nuclear plant is operating at the highest level of efficiency and reliability in the plant's history. Much of this achievement is attributable to careful planning and cost control on the part of Company management and to industry-wide technological advances. The combined result is that CR3 continues to rank in the top quartile of all U.S. nuclear plants in most key performance areas.

We see this operational excellence continuing in future years. PEF is committed to staying abreast of industry best practices through participation in information exchange programs among leading nuclear operators and to maintaining a strong working relationship with regulatory authorities. Our goal is to balance an uncompromising operating philosophy with careful cost control so that the performance of CR3 consistently remains a top performer.

II. Historical Perspective on Nuclear Operations.

Q. Please provide us with an overview of actions the Company has taken since its last rate case to maintain and improve operations at CR3.

A. The nuclear power industry continues to show positive advancements since the Company's last rate review in 2002. Average capacity for the industry is at an all-time high, and average production costs continue to be lower than coal-fired plants. These continued industry advancements, combined with a number of successful management initiatives, have allowed PEF to continue increasing the reliability and performance of CR3 without compromising the safety of our operations.

We continue to focus on transferring maintenance activities from planned maintenance outages to on-line work. This strategy provides cost savings to our customers by decreasing plant outage time. For example, we developed a submittal to the U.S. Nuclear Regulatory Commission ("NRC") to request approval to perform our diesel maintenance on-line versus during an outage. After a rigorous technical review process, the NRC approved our request and we now have our diesel maintenance scheduled during on-line periods and not during our upcoming outage. This will allow previously scheduled outage diesel resources to be utilized for other outage related maintenance projects, thus reducing the time and cost of the upcoming outage.

The Company also continues to focus on improving its employee training and development so that tasks performed during planned outages are accomplished as efficiently as possible. Process benchmarking plays an important role by allowing us to identify and implement industry best practices in specific areas of operation and maintenance. Through better planning and training, we are now able to complete as much work in a short planned outage as was previously accomplished in much longer outages.

In the area of refueling, the Company continues to take advantage of improved benchmarking, planning, and training to reduce downtime substantially and to increase cost savings. In 2003, the plant refuel outage was an outstanding 32 days, which included the reactor vessel head replacement and extensive steam generator inspections. This was an industry world record at the time for the least number of outage days with a reactor vessel head replacement. Our next outage is scheduled for 28 days and again includes extensive steam generator inspections.

Staff reductions also continue to play a role in CR3's success. Through careful planning and organizational changes, our staffing levels are consistent with those of the top operating plants in the country. Since the last rate review, CR3 has continued to benefit from the merger into the Progress Energy Nuclear Generation fleet by eliminating duplicate functions and adopting an organizational structure similar to Progress Energy's other nuclear plants. Our year-end on-site staffing level for 2004 was 501 Company employees, down from 575 Company employees in 2001. This has greatly decreased our annual operating costs without sacrificing plant safety or performance.

We have also made physical improvements to the plant, which have increased the plant's operating efficiency. For example, in 2003, PEF replaced the reactor vessel head after identifying a small crack in the reactor head. By planning in advance to replace the head, the Company reduced future inspection requirements during outages, which results in lower operational costs. This proactive decision also allowed for a cost controlled project approach for the head replacement versus other utilities that were required to replace their reactor heads during a forced outage prior to going back on line.

In addition, in February 2003, the plant completed a power uprate of 4 megawatts. The cost of this power uprate was recovered within the first seven months of the upgrade with the increased power production.

III. Crystal River Nuclear Plant Operating Performance.

Q. Have the efforts you described above been effective in improving the performance of the Company's Nuclear Operations?

A. Very much so. CR3 continues to rank in the top quartile of all U.S. nuclear plants with an annual capacity factor of 99.2 percent in 2004. Our three-year capacity factor for the years 2002-2004 was also in the top quartile, at 96.4 percent.

We have coupled these improvements in plant reliability with significant reductions in generation costs. In 2001, the annual non-fuel production cost at CR3 was 14.8 Mills/KWh, and in 2004, was 11.0 Mills/KWh, which is in the industry top quartile for single unit plants. Our two-year average non-fuel production cost has also steadily improved, decreasing from 14.7 Mills/KWh for the years 2000-2001 to 11.8 Mills/KWh for the years 2003-2004. (See Exhibit Nos. ____ (DEY-2) and ___ (DEY-3).

Importantly, these improvements have been realized without compromising safety or operational excellence. Indeed, as measured by the Institute of Nuclear Power Operations ("INPO") index, a recognized indicator of overall plant safety, CR3 ranks among the best in the country with scores of 98.8 in the year 2001 and 97.3 for 2004.

Since the last rate review, we have also considerably reduced the radiation exposure rate. In 2002, the plant had a record year for the lowest exposure rate in the plant's history at 5 rem. In 2004, we set a new plant record with an exposure rate of 4 rem. This places CR3 in the industry upper quartile for minimizing radiation exposure.

Q. What has been the impact of increased nuclear security requirements since 2001?

A. This has been a major focal point for the NRC and the Company since 2001. We have dedicated considerable resources to bring CR3 into compliance with the various NRC Security Orders and the Maritime Security Act issued since 2001. As a comparison to other NRC Region II (Southeast) nuclear plants, CR3 implemented the various security orders for approximately 50% less than the comparison group. CR3 Security staffing is also considerably less than the average of the other Region II plants.

Since the last rate review, the Company reorganized the nuclear security organization to provide the needed increased security focus and leveraged the security resources of Progress Energy's entire nuclear fleet. This reorganization strategy and security resource focus provided for a cost- effective approach to the implementation of the various security orders.

Q. Do you have plans to extend the license for the nuclear plant?

A. Yes, we do. The current license expires in 2016 and we plan to submit our license renewal application to the NRC in 2009. The submittal will request a license extension of an additional 20 years, to 2036.

Q. Are there other regulatory measures of performance the Commission should consider?

A. Yes. The federal government measures nuclear performance with Performance Indicators that are updated monthly and are available for public review through the NRC Web site. Plant inspection assessments are performed by NRC personnel on a regular basis with performance graded in each area. CR3 has maintained green status (the NRC's highest rating) in all areas since our last rate review.

In addition, CR3 management has been dedicated to continuing a positive relationship with the NRC and has been successful in maintaining good regulatory performance. Since the last rate review, the plant has not received any cited violations resulting from NRC inspections. The NRC continues to keep CR3 on a routine baseline inspection schedule and currently does not plan to add special inspection requirements beyond the current baseline. (See Exhibit No. ___ (DEY-5)).

IV. <u>Proposed Nuclear Operations Cost.</u>

Q. Please provide an overview of the Nuclear Operations costs that the Company is projecting for the 2006 test year.

These figures are set forth in Schedules C-37 and C-41 to the Company's MFRs. We are projecting an increase from benchmark in the amount of $3.3 million. For the test year period, 32 Company employee positions were eliminated for a cost decrease of approximately $2 million but this decrease is offset by increased security costs of $3.3 million. Our material and contracts costs have also decreased during the period in the amount of $2 million. This decrease is a result of improved project focus and controls along with a decrease in the use of contract labor vs. increased use of existing in-house Company labor. We also have an increase in our steam generator inspection costs during planned outages through 2007 of $4 million per outage. We plan to replace the steam generators in 2009.

Q. **Would you explain the procedures the Company has in place to monitor and control Nuclear Operations costs.**

A. PEF has adopted a three-step approach to cost control so that expenditures are scrutinized and evaluated first at the strategic planning phase, again at the design phase, and once more at the implementation phase. All plant modifications must be supported by sound business considerations and cost-benefit analysis in addition to operational justifications. These considerations are carefully assessed at the outset of each phase to take into account any change in circumstances or market conditions. Cost estimates are thoroughly examined for reasonableness and accuracy. This iterative approach has proven quite successful in allowing the Company to assess the reasonableness of O&M and capital expenditures throughout the life of a project.

Q. **Would you please explain the adjustments made to the Company MFRs.**

A. We have included a Company adjustment to the MFRs to account for updated costs relating to the "last core" of nuclear fuel and end-of-life nuclear materials and supplies ("M&S") as they relate to plant life extension through 2036. The cost of the last core of nuclear fuel is established to be $26 million, less the amount already expensed from 2001 through 2004 (4.4 million), which the Company will prorate over the remaining plant life to decrease net operating income ("NOI") by $.7 million pre-tax annually. We estimate the value of end-of-life M&S to be $30 million, which, prorated over the remaining plant life, results in a $900 Thousand annual decrease in pre-tax NOI.

Q. Taking the last core adjustment first, please explain how PEF arrived at $26 million as the estimated value of surplus fuel remaining at end of life.

A. The current budget projection for 2013 core's end-of-cycle value is approximately $30 million. We assume that the final operating cycle will be 18 months instead of 24 months and that the fuel batch size will be reduced from 73 to 54 assemblies. To account for anticipated last cycle loading and operating efficiencies, we applied the ratio of 3/4 to the $30 million current end-of-cycle fuel value, which equals $22.5 million. We then applied the ratio of 54/73 to the $22.5 million to account for the reduced fuel batch size, which equals $16.6 million in 2013 dollars. To account for future increases in fuel cost, the $16.6 million value is adjusted by 2 percent per year for 23 years to arrive at $26 million as the estimated value of the last core.

Q. Is it possible to operate during the final cycle so that no surplus fuel remains at end of life?

A. No. Every core must have excess energy to counter power-reducing effects that necessarily exist during operation. For example, nuclear fuel must have enough excess energy to overcome the negative effects of coolant and fuel temperature, fission products, and required enrichment. This surplus energy must be sufficient to last for the duration of the current operating cycle and for the next one or two cycles of operation. Ordinarily, the excess energy remaining in a fuel assembly at the end of a particular operating cycle is used in the next one or two cycles of operation. At the end of the last operating cycle, however, there are no future cycles in which to use the surplus fuel.

Q. Can the surplus fuel remaining at end-of-life be used in another nuclear reactor?

A. No. Because different reactors use different core designs, the surplus fuel remaining at end-of-life cannot be used in another reactor. Moreover, the fuel reprocessing that would be required to support different core designs is restricted in the United Sates.

Q. Turning next to the adjustment for M&S, please explain how you arrived at the value of $30 million for materials and supplies remaining at end-of-life.

A. We currently have $42 million in inventory. $6 million of this is in spare parts and supplies that are capitalized over the remaining plant life and which will have no value at end of life. An additional $6 million in consumable parts and supplies will be controlled so as to minimize remaining inventory at end-of-life. The remaining $30 million is in spare replacement parts and supplies that we must keep in inventory to make certain that we are operating safely and reliably. While this value is subject to some fluctuation over time, we can reasonably estimate that the value of M&S that we must maintain in inventory to ensure the safety and reliability of our operation will be approximately $30 million. Accordingly, we can reasonably conclude that the value of M&S on hand at end-of-life will be $30 million.

Q. Is there any way to recoup the value of these M&S, for example, selling them to other nuclear plants at end of life?

A. It would be cost prohibitive to do so. Most of these M&S have been specially manufactured for use at CR3 and all have been qualified by thorough engineering analysis to be suitable replacements for existing components in service at CR3. The items at issue include such things as spare pumps and subassemblies, motors, control modules, circuit boards, switch gear, circuit breakers, valves and valve parts, ventilation parts and filters, radiation monitoring parts, and similar types of equipment. Before these items could be used in another nuclear plant, an extensive engineering analysis would be required to confirm their suitability as replacements for existing components at that particular plant. This expensive and time-consuming process makes it impractical to transfer M&S among different nuclear plants.

Moreover, the potential market for these specialized M&S is quite limited. There are only a few nuclear plants with designs similar to CR3, and those plants will be facing end-of-life issues at approximately the same time as CR3. Because of this, the prospect of finding a buyer for CR3's M&S remaining at end-of-life is extremely unlikely.

Q. What is the status of the nuclear decommissioning funding?

A. PEF completed an updated decommissioning cost analysis study for CR3 in 2005. (See Exhibit No. ___ (DEY-4)). The least cost alternative is currently estimated at $668.7 million in 2005 dollars. The NRC-approved decommissioning alternative referenced in the study is for decontamination of all equipment and structures containing radioactive contaminates and removal or decontamination to a level that permits the property to be released for unrestricted use shortly (within 10 years) after cessation of operations. The current decommissioning fund balance is sufficient to cover this cost to the end of extended plant life in 2036.

Q. Are PEF's projected expenses for Nuclear Generation for 2006 reasonable?

A. Yes, they are. The Company's Nuclear Operations are more reliable and efficient than ever before, and these operational improvements have yielded significant cost savings for our customers without compromising the safety of our operations. The merger between CP&L and Florida Progress has allowed us to streamline operations even further, so that CR3 is now on par with the top plants in the country. The expenses projected for the 2006 test year will allow us to maintain the superior performance levels we have seen at CR3 in recent years.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF

DALE D. WILLIAMS

I. Introduction and Purpose.

Q. Please state your name and business address.

A. My name is Dale D. Williams. My business address is Post Office Box 1551, Raleigh, North Carolina. 27602.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Carolinas as a Senior Oil Trader.

Q. Please describe your education and business experience.

A. I earned a Bachelors Degree in Engineering (Energy Conversion) from the University of South Florida in 1973. In 1981, I received a Master of Business Administration Degree from the Florida Institute of Technology. In 1973, I was employed by Florida Power Corporation and began my career in the Plant Performance Department. In that capacity, I assisted with efficiency testing of power plants, and collected and analyzed monthly operating statistics for the power plant monthly reports. In 1975, I was transferred to the Fuel and Special Projects Department. In this department, I was responsible for or participated in the procurement and contract administration for all the fuels utilized by Florida Power for the generation of electricity. In addition, fuel inventory control and price forecasting were part of my responsibilities. I have also participated in various fuel-related special projects, including participation on Florida

Electric Power Coordinating Group (FCG) projects regarding fuel forecasts and fuel emergency plans. In March, 2001, I took the position of Senior Oil Trader. In this position, my responsibilities are similar as those described above, but my activities are primarily focused on fuel oil.

Q. Have you previously testified before the Florida Public Service Commission?

A. Yes. I have previously testified in a number of proceedings involving fuel forecasts and procurement in fuel adjustment dockets. I also testified for Progress Energy Florida ("PEF" or the "Company") in its last rate case on the subjects of fuel price forecasts and inventory target levels.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's fuel price forecasts and inventory target levels.

Q. Have you prepared any exhibits to your testimony?

A. Yes, I have prepared the following exhibits, which are exhibits to my testimony:

- Exhibit No. ___ (DDW-1), a list of the Minimum Filing Requirements (MFRs) schedules I am sponsoring or co-sponsoring.
- Exhibit No. ___ (DDW-2), the Company's fuel price forecast.
- Exhibit No. ___ (DDW-3), the Company's fuel inventories.
- Exhibit No. ___ (DDW-4), a comparison of the Company's fuel inventory levels against Florida Public Service Commission (the "Commission"),

guidelines.

These exhibits are true and accurate.

Q. Are you sponsoring any Minimum Filing Requirements (MFRs)?

A. Yes, they are listed in Exhibit No. _____ (DDW-1). These MFR schedules are true and correct, subject to being updated during the course of this proceeding.

II. <u>The Fuel Price Forecast</u>.

Q. Please describe the basic components of the Company's fuel price forecast.

A. The Company's fuel price forecast consists of a series of discrete forecasts of fuel prices by fuel type. Exhibit No. ____ (DDW-2) shows the projected prices through the year 2006 for the following fuels: coal, oil, natural gas, and nuclear. Different grades of coal and oil are used at different units, therefore the Company forecasts for each grade.

Q. Exactly what type fuels are examined in the forecast?

A. The forecast contains prices for the following fuels:

- Coal - .7% sulfur (1.2 lbs. SO^2/mmbtu) and 1.5% sulfur (2.1 lbs SO^2/mmbtu)
- Oil - 2.4%,1.5% and 1.0% sulfur residual fuel oil and No. 2 fuel oil
- Natural Gas (supply costs into the pipeline)
- Nuclear Fuel

Q. Do these fuels represent the types most likely to be available to and utilized by

Progress Energy Florida over the forecast period?

A. Yes, they do.

Q. Turning now to the individual fuels included in the forecast, will you please explain why Progress Energy Florida's forecast reflects two different sets of coal prices?

A. The Company's forecast reflects two different sets of coal prices because it utilizes different grades of coal at its Crystal River Plant. Specifically, Crystal River Units 1 & 2 burn coal with a 1.5% sulfur content (2.1 lb. SO^2/mmbtu) and Crystal River Units 4 & 5 burn coal with a 0.7% sulfur content (1.2 lbs. SO^2/mmbtu). Different grades of coal are sold at different prices in the market. Thus, the Company must forecast prices for each of the two different grades of coal it utilizes at its Crystal River Plant.

Q. Other than the grade of coal utilized, what other considerations drive the Company's coal forecast?

A Coal prices are impacted by a variety of factors, including the source, the type and quality characteristics, price commitments under existing contracts, the market for spot purchases, and transportation costs to the point of use. Most of the coal expected to be used at the Company's generating plants will be mined in the Central and Southern Appalachian region or South America. The prices in the Company's forecast were derived from current contracts and projected market prices for supply and transportation of such coal to Crystal River.

Q. Focusing next on oil prices, please explain why several different prices have been projected in the Company's study.

A. Oil prices were forecast for three different sulfur grades of residual fuel oil - 2.4%, 1.5%, and 1.0% - and for distillate (No. 2) oil. The No. 2 oil is used at the Company's combustion turbines and at steam plants for start-up and flame stabilization. The 1% and 2.4% sulfur fuel oil is currently used by the Company at its Suwannee River steam plants. The Anclote steam plant normally uses 1.5% sulfur fuel oil. The P. L. Bartow Steam Plant normally burns 2.4% sulfur fuel oil. Like coal, different types of oil are sold at different prices. Accordingly, the Company forecasts each of them separately.

Q. Other than the type of oil, what are the key considerations that affect the price forecast for oil?

A. The projected oil prices are based on estimates of the contract price of oil which include the cost of delivery to PEF's terminals. The oil prices all assume bulk, waterborne deliveries to West Coast Florida Terminals used by the Company indexed to U. S. Gulf Coast market prices. Transportation costs to individual plants are treated as a separate adder.

Q. Please describe the derivation of the nuclear fuel price forecast.

A. The nuclear fuel forecast incorporates the expected fuel expenses for Crystal River Unit 3.

Q. What are the key considerations that affect the price of natural gas?

A. The natural gas forecast is based on the contract structures and spot market prices expected to be in effect during the forecast period for supply into the pipelines which deliver the fuel into Florida. Pipeline transportation charges are forecasted separately.

III. <u>Fuel Inventories</u>.

Q Which of these fuels does the Company keep in inventory?

A As shown in Exhibit No. _____ (DDW-3), the only fuels PEF currently maintains in inventory are coal and oil.

Q. What is the objective of the Company's fuel inventory target levels for each of these type fuels?

A. The Company's objective in establishing fuel inventory target levels is to maintain system fuel inventories at optimum levels consistent with operational and financial considerations. In determining these inventory levels, attention is given to several considerations, including:

1. Projected operating requirements and costs based on the system constraints and anticipated demand;
2. Fuel storage, transportation and handling capabilities;
3. Potential interruptions in fuel supply, their expected duration and frequency; and
4. Current and future fuel market conditions.

Q. Would you describe generally the procedure followed in establishing the

Company's fuel inventory target levels?

A. Because of continuing changes in unit availability, economics, and logistics, target inventory levels are evaluated for each fuel type on a total system basis, as well as for each generating facility. Actual inventory levels are monitored daily, and inventory targets are reviewed and revised as necessary when changes in system requirements and capabilities occur. The target levels for each fuel type are also used as input to the Company's financial model for the projection of fuel expenses and inventory balances.

Q. How were the inventory target levels identified in this case developed?

A. The system inventory target level for each generating plant was established by the process described above. In connection with oil inventory, the Company must also consider the storage capacity at the oil terminals owned by PEF, expected requirements, and the specific delivery modes available at each terminal. Based upon this analysis, along with the one previously described, the Company was able to establish the system inventory target levels for oil that are recorded in the MFRs. These target levels are also shown by fuel type in Exhibit No. ____ (DDW-3).

Q Does the development of coal inventory levels occur in substantially the same way?

A. Yes. However, additional considerations include potential supply problems with mining sources and with barge and rail transportation. The storage capacity available near New Orleans is also a consideration when evaluating coal inventories at Crystal River.

Q. How do the total fuel inventory target levels compare with the Commission's guidelines established in Order 12645 in Docket No. 830001-EU?

A. As can be seen in Exhibit No. _____ (DDW-4), on a total dollar basis, PEF's inventory levels are comparable with the guidelines.

Q. Does this complete your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF
DALE OLIVER

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is Dale Oliver. My business address is 452 E. Crown Point Road, Winter Garden, Florida 34787.

Q. By whom are you employed and in what capacity?

A. I am the Vice President for Progress Energy Florida, Inc.'s ("PEF" or the "Company") South Central Region.

Q. What are the duties and responsibilities of your position with Progress Energy Florida?

A. In this position, I oversee the Company's distribution operations within one of PEF's four geographic regions. The South Central Region roughly covers the area including Highlands, Hardee, Polk, Osceola and Orange counties. Prior to assuming this position in May 2004, I was PEF's Director of Commitment to Excellence ("CTE") with responsibility for overall management of the program, but with particular emphasis in the areas of Transmission and Distribution.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor's degree in Electrical Engineering from Georgia Tech in 1981 and an MBA from Georgia State University in 2001. Prior to assuming my role as Director of Commitment to Excellence for PEF in October 2002, I was the Director of

Transmission Engineering at PEF, which focused on the engineering aspects of substation, transmission line, and relay design. Prior to joining the Company in January 2001, I held a number of supervisory and management positions in the transmission maintenance and operations area for The Southern Company (Georgia Power) in Atlanta, Georgia. I am a registered professional engineer in the states of Florida and Georgia.

Q. What is the purpose of your direct testimony?

A. I appear on behalf of PEF to discuss the Company's CTE program and to support the key initiatives that the Company completed as a part of this program. I will describe the CTE program and its development, how we managed the program, the initiatives we undertook, focusing on our transmission and distribution system initiatives, what we spent, and the results we achieved.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibit to my direct testimony:

- Exhibit No. ___ (DO-1), a summary of CTE spending that shows spending for distribution, transmission, fleet and facilities programs, which represent substantially all of our incremental CTE funding.

This exhibit is true and accurate.

Q. Please summarize your testimony.

A. We successfully completed our Commitment to Excellence program, making significant improvements in several areas of our operations for employees and customers. For our employees, we improved safety, reduced the average age of our fleet, improved our facilities, and improved overall employee satisfaction. For our customers, we lowered our price and improved our service, reliability, and generation adequacy. Over the 2002 to 2004 period, PEF spent $123 million on a portfolio of CTE initiatives, with the vast majority of the funds designed to improve our distribution and transmission performance. These initiatives resulted in improvement over a broad range of reliability performance metrics and, most significantly, resulted in a reduction of our distribution SAIDI to 77, allowing us to meet our commitment of SAIDI 80 or below by 2004.

II. <u>Commitment to Excellence (CTE)</u>.

Q. Please describe PEF's CTE program and its purpose.

A. CTE was a three-year program that we implemented from 2002 through 2004 to make specific and measurable improvements to, among other things, our transmission and distribution systems. The Company undertook CTE to achieve top-quartile performance in major areas including safety, price, service, and reliability, while increasing generation reserves for our customers. CTE was also designed to improve employee satisfaction and to focus our employees after the merger between Florida Progress Corporation and Carolina Power & Light Company on strengthening the Company's culture of continuous improvement.

Q. Please generally describe the major areas that the CTE program addressed?

A. CTE was primarily designed to make improvements for employees and customers. From an employee perspective, CTE addressed several areas designed to engage people and drive performance. From a customer perspective, CTE addressed several areas to improve price, service, and reliability. CTE transmission and distribution projects were separately funded over and above our normal base capital and O&M budgets.

Q. Was CTE a success?

A. Yes. PEF achieved outstanding results. Through CTE, we made significant improvements to many key aspects of our business:

Culture. Following the merger, we strengthened our corporate culture to one that is increasingly performance-oriented and focused on continuous improvement. One metric that best captures the elements of this change is our improving employee satisfaction, even amid an atmosphere of increasing pressure for performance. We improved employee satisfaction significantly, as measured by our Employee Opinion Survey, since our 2001 post-merger baseline. This increasingly satisfied and engaged workforce underlies, and has in large part, enabled PEF to achieve the other CTE goals.

Safety. We have improved our OSHA recorded incident rate to near first quartile relative to our peer utilities based on most recent benchmark data. This is significant because the safety of our employees is our most important goal and because we believe that safety improvements drive excellence in other areas of our business.

Price. As discussed in Bill Habermeyer's testimony, we made significant progress in the reduction of our residential price per 1,000 kWh in comparison to other electric utilities in Florida. By the end of our CTE program in December, 2004 our price of $89.11 was ranked eleventh out of fifty-one Florida electric utilities versus $93.41 and a ranking of thirty-third in 2001, before CTE began. We are very proud of this relative reduction because it was made possible by a 9.25 percent drop in the base rate component of our residential price, and as much as a sixteen percent drop for the typical 1,000 Kwh residential customer, before the impact of increasing fuel costs. We understand that fuel increases may continue to put upward pressure on our overall price in 2005 and beyond and we are working diligently to mitigate this impact on our customers wherever possible.

Customer Service. Our performance in the area of customer service, as measured by the customer service component of the JD Power & Associates 2004 Electric Utility Residential Customer Satisfaction Study, has improved from third quartile in 2001 to first quartile in 2004. The work that we have undertaken to improve our service to customers and the results that we have achieved in this area are described in more detail in the testimony of Willette Morman-Perry.

Reliability. We successfully met and exceeded our commitment to reduce our 2004 System Average Interruption Duration Index ("SAIDI") to 80 minutes. Our actual performance for 2004 was 77 minutes, representing a 23% reduction from our level of 100.6 minutes in 2000. This represents top-quartile performance among our peer utilities as measured by 2003 benchmarks and is likely to fall within the top quartile when comparison data from 2004 is available. My involvement as Director of CTE was primarily focused in this area and I will discuss these results, along with our favorable transmission reliability results, in more detail in the sections that follow.

Generation Reserve Margins. Since 2002 we increased the generation reserve margin that we maintain for our customers from 15% to 20%. Along with the other Peninsular Florida Investor Owned Utilities ("IOUs"), PEF committed to achieve this increased reserve margin by the summer of 2004. We actually achieved this level approximately six months early in December, 2003, with the commencement of operations at our Hines 2 combined cycle power plant in Polk County.

Fleet & Facilities. In the last four years, we have added new service trucks (reducing the age of our fleet), improved the consistency of vehicles and associated maintenance programs, and added four new state-of-the-art operating centers. These improvements have helped our employees better serve customers while boosting employee morale.

III. CTE Distribution and Transmission Initiatives.

Q. Please describe how the CTE program was managed.

A. The CTE program was launched by Bill Habermeyer at the beginning of 2002 with a portfolio of initiatives spanning employee satisfaction, safety, price, service, reliability, and generation. Given that a significant portion of the CTE budget addressed transmission and distribution reliability initiatives, shortly after the launch of CTE I was appointed Director of Commitment to Excellence to specifically manage the program.

As Director of CTE, I ensured that the transmission and distribution reliability programs that we had chosen were implemented on time and on budget. The transmission projects were managed from a system perspective to maximize the effects of the network, while the distribution projects were managed at a regional level due to the volume of the devices and programs being implemented. As the overall project manager, I and my staff controlled budgeted dollars to complete the CTE initiatives and managed internal and external resources to schedule and complete the work. We monitored program completion, tracked spending, and measured program results. In addition, we managed ongoing changes to priorities and budgets when needed to meet our goals.

The initial portfolio of distribution initiatives was developed under the direction of the Power Quality and Reliability ("PQ&R") Engineering organization. We continued to coordinate with PQ&R Engineering throughout the three years of CTE to ensure the optimum focus of our distribution initiatives and to monitor actual versus anticipated results from the CTE programs. The Transmission System Reliability and Power Quality ("SRPQ") organization provided a similar function for transmission.

Q. How were the individual initiatives that form CTE selected and developed?

A. We first identified clear performance goals that we wanted to achieve, and the metrics that we would use to measure our performance. We then selected a portfolio of initiatives to maximize our progress against those metrics at the least cost.

First, in the area of distribution, we began by developing a set of potential initiatives and quantifying the likely benefits and costs. To best optimize the resulting portfolio of initiatives, we developed statistical estimates, in the form of probability density functions, of the likelihood of outages on various devices, the likelihood that the proposed solution would successfully prevent or mitigate future outages, and the likely costs to implement the initiatives on each device. We utilized a statistical risk analysis approach to evaluate the variability of each of these assumptions in combination and the resulting implications for the optimal portfolio. By utilizing this approach, we were able to drive the maximum SAIDI reduction for a limited amount of resources. To our knowledge, this portfolio optimization of delivery reliability initiatives is the most sophisticated ever conducted in the industry. This assertion is based on our discussions with our peers at industry meetings, in particular the Edison Electric Institute (EEI) and the Southeastern Electric Exchange (SEE). Both of these groups hold regular meetings to discuss industry developments and technology changes, and serve as a forum to share best practices.

In transmission, our approach was similar but simplified due to the much smaller number of critical devices on a transmission system and greater working knowledge of their relative outage risks. Once again, we prioritized a set of initiatives to maximize achievement of selected performance metrics at the least cost, but in this case did so relying more on our working knowledge of the system than statistical optimization. Within each initiative, we generally targeted specific devices based on an assessment of outage risk and the degree of customer impact.

Throughout the process we continued to evaluate our priorities, the initiatives and results to assure that we were applying the right resources to achieve the best results. Goals and budgets were set, approved, and tracked by management. In the case of our distribution programs, statistical optimization models were re-run at least annually to ensure that our portfolio of initiatives continued to be formulated for maximum results.

Q. What initiatives did PEF undertake in the area of Distribution?

A. Our distribution programs broadly fell within the categories of power quality and reliability improvements, system and maintenance improvements, and technology enhancements.

Power Quality & Reliability Initiatives. We designed these initiatives to improve our SAIDI primarily by improving the self-correcting capabilities of our system, further sectionalizing our system to minimize the number of customers impacted by faults, and improving our ability to detect faults. One of the major initiatives that we undertook to improve the self-correcting capabilities of our system was to enhance our fusing coordination schemes on critical feeders. This improved our system's ability to clear faults before momentary interruptions became sustained outages. To limit the number of customers impacted by outages, we added electronic reclosers to our system. These devices act to divide our circuits into smaller sections so that fewer customers are affected when problems do occur. In addition, we further sectionalized lines by installing additional fuses to reduce the average number of customers per fuse. In order to better detect potential faults before they occurred, we utilized infrared inspections. To more quickly locate and restore faults resulting in outages we installed faulted circuit indicators, which provide a bright flashing LED or remote indication to more quickly guide our patrolmen to the source of the problem.

Beyond these initiatives, we also undertook numerous other projects, including reconductoring lines, adding insulation to lines, and applying additional lightning protection equipment.

System Improvement & Maintenance Initiatives. These initiatives were designed to improve the condition of our distribution infrastructure and thereby reduce SAIDI. We conducted numerous visual inspections, taking steps to address and replace or repair equipment that either had an increased risk or an established pattern of causing customer outages. We performed extensive work, including the replacement of underground cable, transformers, and poles, and the implementation of additional vegetation management to reduce tree limb contacts with our lines.

Technology Enhancement Initiatives. In addition to installing new equipment, we leveraged existing and new technologies to make further operations and reliability improvements. These initiatives included the installation of mobile data computers in our service vehicles. This measure improved restoration performance and service order processing by allowing us to route orders and related information directly into our vehicles rather than using less efficient voice calls. In addition, we improved our geographic information system (GIS) database, improving our response time to events. In the area of system control, we added state-of-the-art microprocessor relays on selected feeders to enhance our ability to remotely control and monitor the system.

Q. What initiatives did PEF undertake in the area of Transmission?

A. In transmission, we identified and implemented initiatives addressing three broad categories: right-of-way management, equipment improvement, and substation enhancements.

Right-of-Way Management. We designed these initiatives to improve our transmission reliability performance through better management of our right-of-way. Among other things, we more aggressively addressed encroachment issues, cleared vegetation away from our lines, and applied herbicide to reduce future vegetation growth.

Line Improvements. Our line initiatives focused on improving the response of our system to lightning activity and reducing component failures. We first identified the lowest performing lines, taking into account customer impacts. We then inspected and, as warranted, replaced or refurbished transmission structures, including cross arms, wedge connectors and overhead ground wire. To better protect our lines against lightning, we improved the bonding and grounding on many transmission structures and installed additional lightning arresters. In addition, we piloted the use of microprocessor relays to better locate line faults in real time as a way to shorten the duration of an outage. To prevent contact with animals, which is a significant cause of outages, we installed more barriers and bird dishes in targeted areas. Finally, we installed motor operated switches to enhance the ability of our system to remotely sectionalize and minimize customer impact in the event of an outage.

Substation Enhancements. Our substation initiatives focused on improving the physical condition of our substations and related equipment, improving security access control, improving lightning protection, reducing contact with animals, and adding equipment for enhanced system information and flexibility. These efforts included the inspection and replacement or refurbishment of breakers, batteries, bushings, arresters, and insulators. In addition, we renovated a number of substations to improve their performance and operability and repaired substation gates for better access security. We installed additional barriers around many substations to prevent animal contacts with our equipment and associated customer outages. We added digital fault recorders to pinpoint the location of faults along the system so that repair crews could be quickly directed to the source of the problem instead of patrolling an entire line, thus shortening the duration of transmission outages. We also purchased a mobile transformer to serve as a backup and provide temporary power for customers in the event of a substation failure within the system.

Q. What adjustments to the program were made during the CTE program and why?

A. Throughout our implementation of the CTE program, we monitored the effectiveness of the initiatives and made adjustments as changing circumstances warranted. During the CTE program, we continued to prioritize those initiatives that would produce the most significant system SAIDI reduction at the most reasonable cost. As a general rule, this philosophy guided us to prioritize mitigation programs, which would significantly impact SAIDI by reducing the duration or frequency of outages that did occur, as opposed to those targeted more toward the prevention of faults but offering a lesser impact on SAIDI.

Our assessment of project priorities matured as we gained experience in implementing the various projects and gathered performance data resulting from them. In some cases, we reallocated funding to initiatives that were producing better-than-anticipated results from those that were showing less ability to achieve our goals. As examples, we elevated midpoint reclosers, fusing coordination, and the installation of sectionalizers to a more significant role in our overall program due to the excellent results that we were seeing from these initiatives.

Q. How much did the Company spend on CTE?

A. Our spending for CTE from 2002 through 2004 totaled $123.0 million. Of this amount, we spent $56.9 million on distribution-related projects, $37.2 million on transmission-related projects, $16.3 million on fleet services, and $12.6 million on facilities. Please see Exhibit No. ___ (DO-1) for a further breakdown of these amounts.

IV. CTE RESULTS.

Q. Please describe the distribution reliability results you achieved through CTE.

A. As I stated earlier, we improved our system SAIDI by 23% to 77 minutes from 2000 through 2004. By doing so, we met and exceeded our commitment to achieve a SAIDI of 80 minutes by the end of 2004 and achieved top-quartile performance among our peer utilities based on most recent benchmarks.

In addition to improvement in our top-line SAIDI results, we achieved consistent improvements in a broad range of reliability measures. The breadth of our improvement is highlighted by the Florida Public Service Commission's ("FPSC's") most recent "Review of Florida's Investor-Owned Electric Utilities' Distribution Reliability" report. This review of reliability by the FPSC covers the 4-year period from 2000 through 2003 and shows that PEF demonstrated meaningful improvement in seven out of eight reliability metrics examined. The next closest company showed improvement in only four of these same eight metrics.

Accounting for our most recent 2004 results, and examining the period covered by CTE, our performance trends are also very favorable. From 2001, prior to the start of CTE, to 2004, PEF reduced its customer's average minutes of interruption ("SAIDI" – System Average Interruption Duration Index) from 89.7 to 77. Over the same time period, our average frequency of outages ("SAIFI" – System Average Interruption Frequency Index) dropped from 1.3 to 1.19. We reduced the average duration of our outages ("CAIDI" – Customer Average Interruption Duration Index) from 68.7 to 64.7 over the same time period. Our percentage of customers experiencing 5 or more interruptions ("CEMI5" – Customers Experiencing Multiple Interruptions) also dropped from 1.81 to 1.37.

Q. Please describe the transmission reliability results you achieved through CTE.

A. To best gauge the results of our transmission CTE initiatives, we developed, tracked, and in fact incorporated into our incentive compensation, a metric called the "Transmission Improvement Index." This performance indicator captures two main elements of transmission performance. First, it measured year-by-year improvement in line performance as measured by "FOHMY" (Forced Outages per One Hundred Miles of Line per Year) operations. Second, it measured year-by-year improvement in customer outage performance as measured by either "CMI" (Customer Minutes of Interruption) or the total number of outage events from relevant causes. We maximized our performance against annual targets for the Transmission Improvement

Index in total and for both of the underlying categories each year. In 2004 alone, these measures improved by 40% and 52%, respectively, over prior year performance.

Q. Are there any other comments you'd like to add about these performance improvements?

A. Yes, it is worth mentioning that the distribution and transmission reliability achievements outlined above are even more noteworthy when one considers the adverse weather conditions that we experienced during the CTE period, as measured by the number of lightning flashes striking our service territory. Relative to the preceding five-year average, representing the period from 1997 to 2001, lightning flashes experienced within PEF's service territory for the years 2002, 2003 and 2004 were up by 4%, 44% and 60%, respectively.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF
RAY F. DESOUZA

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is Ray F. DeSouza. My business address is 3300 Exchange Place, Lake Mary, Florida.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") in the capacity of Director, Transmission Engineering.

Q. What are your duties and responsibilities as the Director of Transmission Engineering?

A. As Director of Transmission Engineering, I have the responsibility of leading PEF's transmission engineering section which provides both technical and project management support for transmission projects. I direct the activities of this 83 employee team that develops project feasibility studies, creates engineering design packages, and manages the schedule and budget for major transmission maintenance and all transmission capital projects. The section also supports our transmission asset management group in providing technical support, like engineering studies and standards, to the transmission operation groups. As director of the section, one of my primary responsibilities is to ensure that the team has the capacity to provide the highest level of technical and project management services and that all of our activities are aligned in support of the Company's goals.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of South Florida in 1987 with a Bachelor of Science in Electrical Engineering and received an MBA from Rollins College in 2003. I joined Florida Power in 1987 as an engineer in the Transmission Engineering section designing transmission facilities for major capital projects. In 1995, I moved to the Transmission Standards and Technology group and assumed responsibility for developing specifications and engineering support for major substation equipment. In that capacity I led teams to accelerate the use of computer-aided design tools in the engineering units and initiated strategic alliances with some of our equipment suppliers. I became a supervisor in the Transmission Engineering section in 1999 with responsibility for managing the activities and resources required for our drafting function. In 2001, I was promoted to Manager of Substation Engineering providing technical support for all substation capital projects and some major maintenance projects. In 2002, I was promoted to Director of Transmission Engineering.

I am a registered Professional Engineer in the State of Florida and a member of the Institute of Electronic and Electrical Engineers. I represent PEF in the Southeastern Electric Exchange.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the reasonableness of the transmission portion of PEF's capital and O&M expenses.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. ___ (RFD-1), entitled Minimum Filing Requirements Schedules Sponsored, All or In Part, by Ray F. DeSouza.
- Exhibit No. ___ (RFD-2), entitled Transmission Florida Reliability Graphs.
- Exhibit No. ___ (RFD-3), entitled Transmission Florida Accelerated & Proactive Reliability Initiatives.

These exhibits are true and accurate.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements (MFRs)?

A. Yes, I sponsor MFR schedules as outlined on Exhibit No. ___ (RFD-1) insofar as they pertain to transmission. These are true and correct, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. Since 2002, we have made significant improvements to, and increased the reliability of, PEF's transmission system. We accomplished this through effective management, a continuing emphasis on safety, operational excellence and customer service, and an increased investment in reliability initiatives. We have achieved these improvements while meeting the increasing service demand on the Florida grid resulting from new load and new generation supplies. The customers' expectations for reliable service, however, continue to rise and we must continue to be proactive in our efforts to meet these demands.

Historically, the Company's transmission system has benefited from a very robust design, providing exceptional ability to isolate faults and limit the impact to small sections of the system. Nonetheless, since 2002, we have made significant, additional reliability investments to replace equipment in order to meet the rising customer demands. Through our Commitment to Excellence ("CTE") program alone, we invested $37 million on 22 initiatives between 2002 and 2004 to improve transmission system reliability. And as discussed in greater detail in Dale Oliver's testimony, these initiatives included aggressive vegetation management, animal mitigation, and line bonding and grounding programs. We have also invested in improvements to our operation and maintenance activities through the establishment of an asset management group, through the implementation of more efficient data and asset management tools, through increased training of our craft and technical personnel, and by driving accountabilities for system performance to the individual employee level.

Through CTE and improvements in operation and maintenance of the system, PEF improved transmission reliability by 37% since 2002. PEF retail customers experienced year-over-year improvements in transmission-related SAIDI (System Average Interruption Duration Index) throughout the three-year period.

While we have made significant improvements in the transmission system, we remain committed to continuing to provide superior service and to meet our customers' rising expectations. Going forward we will focus on increasing the effectiveness of our maintenance program through enhancements of our work management systems and transitioning to a predictive maintenance model. We plan to maintain an aggressive posture on refurbishing and replacing aging equipment. We also plan to implement projects to modernize older designs/equipment.

To this end, we are anticipating total transmission capital expenditures of $91.7 million in 2006, which includes base funding, reorganization savings, and accelerated and proactive initiative funding. We are anticipating O&M expenses of approximately $36.754 million in 2006, which includes base funding, reorganization savings, and accelerated and proactive initiative funding. This will enable the Company to strike a reasonable balance between high quality of service that our customers expect and a reasonable cost for that service.

II. <u>PEF's Reliability Initiatives Since 2002</u>.

Q. Please summarize the transmission system reliability initiatives that the Company has undertaken since 2002.

As discussed in greater detail in Dale Oliver's testimony, in 2002, PEF committed to further improving the level of service to its customers. The Company developed a comprehensive program, CTE, to target areas, including the transmission system, where reliability improvements could be made. Under the CTE program we developed specific, measurable goals with the ultimate objective of reaching top quartile performance in key categories. We then identified and prioritized projects to cost-effectively achieve these goals.

In Transmission, we focused on twenty-two key projects to improve reliability, in particular to reduce SAIDI. These included (1) accelerated line, pole and other equipment inspection and replacement, (2) enhanced vegetation and right-of-way management, and animal mitigation measures, and (3) substation upgrades. As I noted above, PEF spent more than $37 million on these projects.

Our programs yielded measurable improvements. For example, we first targeted the lowest performing transmission lines, i.e., those with the highest outage rates, for bonding, regrounding and repairs. As a result of our efforts, we have seen a 35% improvement in the performance of these targeted lines. This was part of an overall improvement in Transmission "FOHMY" (i.e., the number of forced outages per hundred mile of line per year) during years of increased lightning activity. We then targeted substations with a history of animal related outages by installing protective barriers. As a result of our efforts, we reduced our animal-related customer outage times by more than 50%. We also increased our vegetation management efforts for our transmission right-of-ways. This work resulted in a 50% reduction in tree-related outages from 2002 to the 2003-2004 average. The net result of these various initiatives, as noted before, was a significant improvement in retail SAIDI, going from 16.26 customer minutes for 2002 down to 10.23 customer minutes for 2004. These reliability improvements are shown in Exhibit No. ___ (RFD-2).

In addition to CTE, we continued to focus on improving our maintenance and construction activities. We implemented a new asset management tool in 2002, which has improved our ability to schedule and track equipment maintenance and provided us with a better ability to perform trending analyses on the performance of our major equipment. We have also revised our maintenance procedures to leverage best industry practices, and we have increased training to craft and technical personnel with an emphasis on task related training. We established a project management group to provide a single point of accountability for the life cycle of transmission projects. These are some of the many initiatives in the maintenance and construction areas that helped to promote better reliability performance from 2002 to 2004 on the transmission system.

III. <u>Steps Taken to Monitor and Control Costs</u>.

Q. What steps do you take to effectively manage the Company's transmission-related capital and O&M costs?

A. PEF transmission management takes a number of steps to ensure that we are focused on the right priorities, our budgets are reasonable, and that we are spending money wisely. We have implemented many best practices since the merger between Carolina Power & Light and Florida Progress, which have enabled us to aggressively manage and control costs. In 2001, the Transmission Department instituted a project management organization to augment the engineering group in Florida. Under this organization, Project Managers have responsibility for projects from inception to energization. During budget formation, Project Management supervises the Transmission Department's project ranking process. Projects are prioritized based on ranking criteria such as operational impact and regulatory requirements.

The project rankings are reviewed and approved by the Department's Project Review Group ("PRG"), which is composed of the Department's managers and which provides another opportunity for oversight of capital expenditures. The PRG meets monthly to manage the overall capital budget and assure that emergent projects are evaluated consistently and funded if necessary. The PRG process thus provides for consistency in project evaluation and funding, as well as providing for flexibility in handling the dynamics inherent in a large complex business. The

PRG uses a three-phase project authorization process as a methodology for project development, review, and approval so that an adequate business case is established prior to the commitment of significant resources. This process was implemented in 2002. The three phases are study, design, and implementation. Authorization is required separately for each phase and must be obtained before work starts.

We also utilize benchmarking as a way to measure ourselves against others in the industry and drive continuous improvement in the business. Our organization has made progress on transmission cost benchmarks, ranking in the top quartile on "Total Cost per Gross Plant" and moving towards top quartile on "Transmission Normalized O&M and Infrastructure Capital per Planned Peak". Our budgets and performance metrics are woven into incentive compensation goals for employees at all levels of the organization to ensure focus. Transmission has achieved its O&M and Capital budget goals for each of the three years starting in 2002 through 2004.

Finally, our Business Operations group monitors spending each month for reasonableness and compliance with budget, while also acting as a facilitator for operational analysis, the development of improvement ideas and the revision of spending projections. The mechanisms for cost management used by the Transmission Department provide full cycle accountability and ensure that our expenditures are prudent.

IV. Management Effectiveness.

Q. What other effective management practices has the Transmission organization implemented?

A. We have implemented a number of practices to improve safety, the effectiveness of our workforce, and generally to promote an environment for continuous improvement. These practices have favorably impacted our performance in diverse areas of the business: safety, training, storm response, corporate culture, and corporate restructuring.

Safety: Safety remains a core value for the organization. To that end, we have established very vibrant safety councils in every section in the Transmission Department. These councils are organized and managed by employees on a volunteer basis. The department also establishes safety goals, and employees at every level are accountable for achieving these goals. The result has been an improvement in our OSHA injury rate from 3.04 in 2002 to 1.64 in 2004.

Training and Development: We instituted training advisory boards for the various disciplines in the organization. The boards provide direction for the development of training programs in the department. The System Performance unit, which is responsible for craft and technical training in Transmission, has increased the total hours of training from 10,696 hours in 2001 to 38,902 hours in 2004. This is reflective of our commitment to employees and to improve the operational excellence of the Company.

Human Performance: In 2002, Human Performance (HP) was implemented in PEF (T&D). The objective of HP is to reduce incidents of human error that can lead to injuries, customer outages, or equipment damage. In support of this initiative, Transmission has an infrastructure to promote HP within the organization. This is spearheaded by the Transmission HP Steering Committee and supported by smaller HP committees in all sections of the department. These committees help to develop programs that encourage event and near-miss reporting, tracking and trending of events, and the development of promotional activities to keep HP as a top of mind item with our employees. Since 2003, when we started tracking, the number of customer impacting events due to human error has been reduced by 32%, from 53 to 36.

Storm/Hurricane Preparedness: As we learned during the unusually active storm season last year, pre-storm preparation and readiness are critical success factors in restoring power quickly after the event. In the years preceding summer of 2004, the Florida transmission organization leveraged the storm experience of the Carolina organization by modeling their storm organization, storm plans, and storm drills. During the 2004 storms, for example, we were able to augment our staff with experienced personnel from Carolina at all levels of the organization. This preparation paid enormous dividends: in the aftermath of four hurricanes, with 2,684 miles of damaged transmission lines and 274 substations impacted, Transmission was able to safely restore power to over 90% of the affected substations prior to the daily estimated time of restoration (ETR). This enabled retail service to be restored as described in Jeff Lyash's testimony.

Diversity and Corporate Culture: Employees are the most important investment of any organization. As such, employees are valued for their skills, abilities, and contribution to the organization regardless of their background. Our corporate culture centers on People, Performance, and Excellence. From our annual employee surveys, we have seen steady improvement in our employee satisfaction results and diversity scores from 2001 to 2004. Our transmission employee

employee surveys, we have seen steady improvement in our employee satisfaction results and diversity scores from 2001 to 2004. Our transmission employee satisfaction score improved from 72.8 in 2001 to 82 in 2004. Our diversity score rose from 77.8 to 82 during the same period. We have also focused on supplier diversity and have achieved strong results. In 2003 and 2004, we sourced $ 2.7 million and $ 3.3 million of transmission business from minority owned businesses.

Corporate Restructuring: Included in our funding request is the amount of transmission O&M savings of $0.893 million associated with the Company's current reorganization effort. The Company is undertaking a complete review of its organizational structure in order to once again identify areas where further efficiencies can be achieved. This initiative, which will be implemented throughout 2005 and will include employee incentives for voluntary early retirement, is expected to produce nearly $20 million in O&M savings in 2006, with roughly $ 0.893 million in the transmission organization. These savings result from our constant focus on improving efficiency and eliminating redundancies to ensure the maximum use of our resources.

V. Accelerated and Proactive Transmission Reliability Initiatives.

Q. Please provide an overview of your Capital and O&M expense forecasts for maintaining PEF's transmission system.

A. From 2002-2004, we addressed and successfully implemented measures that mitigated the number and duration of outages occurring on the system. Reliability is measured by the index SAIDI, which is a product of the average minutes of outage time per customer on our system as well as FOHMY, which is the number of forced outages per hundred mile of line per year. Over the years 2002–2004 we reversed a prior negative trend and instead experienced significant improvements in these reliability measures. The transmission SAIDI has dropped from 16.26 to 10.23 minutes and FOHMY has dropped from 15.9 to 14.97 during this period. Moving forward, we will continue to focus on mitigating customer outages by implementing initiatives that will further strengthen our grid and enhance the operation of our system.

We are anticipating total transmission capital expenditures of $91.7 million in 2006, which includes base and initiative funding. We are anticipating O&M expenses of approximately $36.754 million in 2006, which includes base and initiative funding. The annual initiative funding will be $10 million in O&M expense and $15 million in capital. These 26 specific reliability initiatives are outlined in Exhibit No. ___ (RFD-3).

The initiatives can be classified into two types of activities: accelerating asset refurbishment and/or replacement, and proactively modernizing aging designs and/or equipment. The work activities cover a cross-section of transmission assets including transmission lines, substations, and relay protection and control. The accelerated asset refurbishment and/or replacement includes initiatives such as more aggressive vegetation management, targeted line inspection, bonding and grounding, conductor replacement, wedge connector removal, transformer replacements and repairs, bushing repairs, and renovating various substation equipment. The modernizing of designs and/or equipment includes initiatives such as targeted wood pole and cross-arm replacement, animal mitigation barrier installation, breaker replacement, adding load break capability to switches, and modernizing various substation equipment. These initiatives can be broadly defined as proactively modernizing outdated designs with current design standards to improve performance and reliability.

Q. Are the projected transmission Capital expenditures and O&M expenses for 2006 reasonable?

A. Yes. More than that-they are necessary. At the level of funding noted above, the adjusted transmission O&M expenditures will be within $0.04 million of the FPSC O&M Benchmark cost of $36.713 million. In addition, we have ranked in the top quartile on "Total Cost per Gross Plant" and are moving towards top quartile on "Transmission Normalized O&M and Infrastructure Capital per Planned Peak". As discussed earlier, this level of funding will support baseline operating and maintenance activities, accelerate equipment refurbishments, and allow proactive system upgrades in order to strengthen the transmission grid and enhance the operation of our system. These expenditures are therefore reasonable and necessary to strike an appropriate balance between the high quality of service that our customers expect and a prudent cost for that service. PEF has remained committed to this objective over the years and will continue to do so.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF
DAVID MCDONALD

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is David McDonald. My business address is 100 Central Avenue, St. Petersburg, Florida.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company"). I am the Director of Distribution Asset Management in PEF's Energy Delivery Business Operations.

Q. What are your duties and responsibilities?

A. As Director of Distribution Asset Management, I direct and manage the Company's distribution reliability and maintenance programs as well as all distribution relocation and system expansion activities.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering from the University of Kentucky in 1984. Prior to assuming my current role for PEF, I was the Distribution Control Center Director, responsible for the operation of the distribution system grid and the coordination of PEF's nineteen (19) operating centers throughout its service territory. Earlier, I served as a Distribution Region General Manager for PEF and a Distribution Region Engineering Supervisor for Progress Energy in the Carolinas. Prior to joining Progress Energy in 1998, I held a number of supervisory and management positions for Florida Power & Light Company.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to discuss the Company's distribution operations and system reliability and to support the reasonableness of Capital and Operations and Maintenance ("O&M") expenses in the Company's distribution area.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. ___ (DM-1), a summary of sponsored or co-sponsored schedules of the Company's Minimum Filing Requirements (MFRs).
- Exhibit No. ___ (DM-2), a summary of planned distribution reliability initiatives.

These exhibits are true and accurate.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements (MFRs)?

A. Yes, please refer to Exhibit No. ___ (DM-1) for a list of schedules of the Company's MFRs that I sponsor or co-sponsor with respect to the Company's distribution system. These are true and correct, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. PEF's distribution reliability performance has improved significantly since our rate settlement in 2002. This was accomplished through the successful completion of our Commitment to Excellence (CTE) program as well as other, additional initiatives. Together, these efforts enabled the reduction of our System Average Interruption Duration Index (SAIDI) to 77 minutes, exceeding our commitment of 80 minutes by 2004, and produced improvements in many additional areas of our business. At the same time, we have diligently managed costs while striving to meet the challenges of a quickly growing customer base and rising customer expectations.

Going forward, we remain committed to continuing to provide superior service and meeting our customers' rising expectations. We believe that we can provide the most visible and valuable improvements for our customers at the lowest cost by maintaining the SAIDI improvements we have achieved while broadening our focus beyond mitigating the impact of outages to the actual prevention of faults and beyond focusing on system average results to one that includes "outlier" customers experiencing lengthy or numerous outages. In order to both preserve our reliability gains and implement this broadened reliability focus, we plan to take an increasingly aggressive posture on refurbishing and replacing equipment before it fails and to institute several system improvements that will deliver these benefits to customers. To this end, we are proposing twelve specific incremental distribution reliability initiatives representing $17.3 million in capital and $18.7 million in O&M in our 2006 test year that will accelerate or go beyond existing levels of activity. This plan represents an appropriate balance between the quality service that our customers expect and reasonable costs.

II. Distribution System Performance Since 2002.

Q. Please provide an overview of the Company's distribution reliability performance since the last rate case.

A. PEF made a commitment to reduce our SAIDI to 80 minutes by 2004 in conjunction with our 2002 rate settlement agreement. This represented a 20% improvement from our 2000 level of 100.6 minutes. I am proud to say that the Company not only achieved that commitment but exceeded it with a 23% improvement and a system SAIDI of 77 minutes for 2004. This represents top-quartile performance among our peer utilities, based on our most recent benchmark data. Beyond this, we have been making year-over-year reductions in the average number of outages (System Average Interruption Frequency Index or "SAIFI"), the average duration of outages (Customer Average Interruption Duration Index or "CAIDI"), and the number of customers experiencing multiple interruptions (Customers Experiencing Multiple Interruptions or "CEMI"). The breadth of our improvement is highlighted in the Florida Public Service Commission's ("Commission") most recent "Review of Florida's Investor-Owned Electric Utilities' Distribution Reliability" report. This most recent review of reliability by the Commission covers the 4-year period from 2000 through 2003 and shows that PEF demonstrated improvement on seven out of eight reliability metrics examined. The next closest company showed improvement on only four of these same eight metrics.

Q. What steps has the Company undertaken to achieve these results?

A. PEF has undertaken a multi-faceted effort since its last rate case to bring about these reliability improvements for our customers. The most significant effort has been our CTE program, which is discussed in detail in the testimony of Dale Oliver. Beyond this, we have continued our commitment to utilize the latest technology for the benefit of our customers and have changed the way we do our work in several critical areas by implementing a number of initiatives, including:

CAIDI Improvement Initiative. We have undertaken specific efforts to reduce the duration of outages. As part of CTE, we installed Faulted Circuit Indicators ("FCI's") devices on feeders to assist our line crews in more easily detecting faults. Beyond this, we have improved our feeder restoration process from typically restoring entire lines at one time to an emphasis on the opportunistic restoration of segments of lines as quickly as possible. Additionally, we have implemented goals and incentives for each of our operating centers to ensure continued focus in this critical area.

Radio System. We have deployed a new radio system throughout Florida, which has significantly improved the communications capability of our crews. This has increased our ability to orchestrate talk groups and improved efficiency in completing complex assignments or party-to-party communications. In addition, because we are using the same system as the Carolinas, our crews are easily able to coordinate during major storm events.

ITR/ETR, OMS. This refers to the "initial" and "estimated" time of restoration information that is given to our customers. Although this does not directly impact actual reliability, it does impact our customers' perceptions of and satisfaction with our reliability. While our system has provided for some time an initial, computer-generated restoration time estimate to customers, we have recently begun to update this estimate in the field and have steadily increased the accuracy of our forecasts. For the year 2004, 92.6% of our ETRs were within one hour of the actual restoration time. We set goals and monitor our performance in this area since our customers have told us that accurate information on outage restoration is important to them.

Weekly rankings & scorecards. This initiative is one example of a cultural shift in the way we do business. We have placed scorecards in each operating center every week that show the prior week's reliability performance and provide a ranking relative to the other operating centers within the system. These scorecards have fostered a healthy sense of competitiveness and have helped us to keep the focus on, and urgency with respect to, reliability among our crews.

We have continually emphasized a culture that is performance-based and focused on continuous improvement. This culture is the foundation upon which we have been able to show year-over-year improvement in the vast majority of the metrics that we benchmark and monitor as an organization. Also, we have successfully applied numerous common systems and processes across our organizations in Florida and the Carolinas. This has allowed us to quickly deploy additional and backup resources during critical times, for example, during the 2004 hurricanes.

III. Steps Taken to Monitor and Control Costs.

Q. What steps do you take to effectively manage the Company's distribution-related capital and O&M costs?

A. We take a number of steps to ensure that we aggressively manage our distribution-related costs and that we are focused on the right priorities, our budgets are reasonable, and we are spending our money wisely. We prioritize our portfolio of reliability capital projects using a sophisticated optimization model at least annually, as described in more detail in the testimony of Dale Oliver.

We also utilize benchmarking as part of how we strive for continuous improvement, set targets, allocate budget dollars, and monitor performance. Our organization performs well overall on distribution cost benchmarks. Since 2002, we have achieved top quartile performance on "Distribution Cost to Install New Service – Before CIAC Reimbursement" and lowered our "Distribution O&M and Capital Maintenance per Customer" from $120 to $102, within the second quartile of our peer utilities based on most recent benchmarks. A Distribution Project Review Group ("PRG") comprised of management from a range of functional areas within PEF provides another cross-check on programs, plans, and budgets, and provides a mechanism to continuously adjust priorities as changing events warrant. At a more detailed level, system load growth prioritization and reliability and maintenance prioritization teams ensure that our budgeted dollars and work plans are targeted to the most critical issues. Our budgets and performance metrics are woven into incentive compensation goals for employees at all levels of the organization to ensure focus. Finally, our Business Operations group monitors spending each month for reasonableness and compliance with budget, while also acting as a facilitator for operational analysis, the development of improvement ideas, and the revision of spending projections.

IV. Planned Distribution Initiatives Going Forward.

Q. What priorities do you have for distribution reliability and the distribution system going forward?

A. Our overarching goal is to meet the needs and expectations of our customers at a reasonable cost. To do this, it is critical that we sustain a distribution system with adequate reserves to meet the demands placed on it, and minimize the number and duration of outages, disturbances, and voltage variations to our customers. Over the past several years, we have made significant improvements to our overall system reliability and we intend to build on this momentum. As I mentioned, we have reduced our system SAIDI by about 23%, from 100.6 minutes to 77 minutes since 2000. This level of performance is within the top quartile of our peer utilities, based on most recent benchmarks. We have been able to achieve these results by a strong focus on the mitigation of outages, for example, by reducing the average duration of outages and reducing the number of customers affected by outages that do occur.

Now that we have achieved this level of performance, we believe that we can bring about the most significant improvements in customer satisfaction by maintaining our SAIDI reliability measure in its current range and gradually broadening our focus from the mitigation of outages to the improvement of power quality through fault prevention. Two common ways of measuring these impacts are "MAIFI" (Momentary Interruption Frequency Index) and "CEMI" (Customers

Experiencing Multiple Interruptions). In addition, we intend to broaden our focus from system average results to the "outliers," that is, those customers experiencing especially lengthy or numerous outages. With system average performance at top-quartile levels, the most significant customer benefits can be achieved by focusing our attention on those areas that lag behind system average performance levels. We believe this broadening and re-balancing of priorities will produce in the future the most visible and valuable improvements for our customers at the lowest cost.

Q. What principle factors have influenced the Company's future distribution plan?

A. Two principle factors are driving our distribution plan forward: (1) the growth within our service territory; and (2) evolving customer expectations. First, the growth within our service territory has been and is projected to be significant. We anticipate adding in excess of 30,000 customers per year to our system in the coming years, a number that will be experienced by only a very few electric utilities in the country. This growth will be across all customer classes, from residential to industrial and governmental. What is important about this trend is not only the quantity of growth, but the nature of that growth as well. Nationally, and in Florida as well, we are seeing a movement from the use of simple equipment and processes to more sophisticated equipment and more intricate processes that result from a more service and information-based economy. For example, budget recommendations introduced by Governor Bush for fiscal year 2005-2006 show a continued focus on economic development, particularly of high-technology industries, in Florida.

Second, customer needs and expectations are quickly evolving. It is clear that the use of computers and other sensitive and sophisticated equipment is increasing across all customer classes. Our customers are changing, and their needs and expectations for reliable electric service are changing as a direct result. Beyond increased reliability, customer expectations are evolving in other areas. As they become accustomed to increased automation in almost all aspects of their lives, they assume and expect the same for their electric service. Timely and accurate bills, with increasing amounts of usage information, produced through increasingly automated processes are the expectation. Also increasingly important to our customers is the delivery of our service through underground rather than overhead cables. Today, about 90% of our new customers are being connected to the system with underground service. Conversions from overhead to underground service are less common largely due to the high cost of completing such projects, but are increasingly being mentioned, studied and requested by customer groups.

Q. What issues do these trends present for your business and how do you plan to address them?

A. A rapid customer growth rate and evolving customer expectations represent excellent opportunities for our Company, but they also present numerous operational and financial issues.

Some of the most critical issues driven by the high customer growth include:

<u>Underground Service.</u> The increasing demand for underground service, both in the past and projected into the future, presents a range of issues for our Company. First-generation underground cable that was installed in the 1970's and

early 1980's, a period of particularly explosive growth in our service area, was originally thought by the industry to have a useful life of 40 years or more, roughly consistent with that of overhead cable. In addition, it was thought that on-going costs would be comparable to or lower than overhead service. Actual industry and PEF experience has shown that some of these cables are beginning to wear out and are requiring replacement sooner than previously expected. Replacement of underground cable is costly. Underground systems are expensive to install or replace due to high material component labor, trenching, and site restoration costs. Maintenance costs are high as well due to numerous challenges brought about by the placement of equipment on or under the ground. As an example, reclaimed water systems are forcing much more frequent maintenance of pad-mounted transformers than we have ever experienced with overhead transformers. Similarly, restoration costs for underground systems can be quite high. Even though outages, depending on a number of factors, can be only one-half as frequent as for overhead service, fault location and restoration activities are much more complicated and time consuming for underground service.

The nature of the work we must accomplish includes substantial replacement of aging underground cable that is failing at an increasing rate and is adversely affecting reliability. In addition, we must fund increasing levels of maintenance and replacement of underground system components, including pad-mounted transformers and switch cabinets.

<u>System Loading.</u> Heavy growth has also placed a burden on the loading of our distribution system. We have responded to these challenges by attempting to balance cost and resource utilization with appropriate operating margins on our

substations, feeders, and other system equipment. We need to expand our infrastructure going forward to meet this demand.

Equipment Relocations. Equipment relocations are another example where growth is increasing our costs. Due to mounting population growth, we are increasingly forced to relocate our equipment due to roadway widening, and other municipal right-of-way projects. These activities comprise a substantial cost to the Company, projected to be $14.0 million in 2006, versus $9.4 million as recently as 2002.

Some of the most critical issues driven by evolving customer expectations include:

Power Quality Emphasis. Our customers are increasingly focusing on power quality. To meet these expectations, we must go beyond the mitigation of system outages and re-balance our focus to the actual prevention of faults. This includes focusing on momentary interruption prevention and the prevention of sags and other voltage variations that may result for nearby system components and customers. The nature of the work we must accomplish to drive successful fault prevention includes the replacement of system components that are suspected of having a high likelihood of failure, and the prevention of potential contacts with our system through such measures as continued aggressive vegetation management.

Increased Information & Timeliness. As a Company, PEF is committed to implementing the right processes, tools, and technologies to improve the amount and timeliness of information for customers. Although this will be an evolution rather than an event, we have taken a major step with our Mobile Meter Reading initiative. This program will transform our traditional meter reading process to one in which data is transmitted wirelessly from a radio-based module that fits on the electric meter to a vehicle that polls the information as it passes through the vicinity of the meter. Instead of reading 400 meters per day by walking door-to-door, each meter reader will be able to read about 10,000 meters per day using this technology. The efficiencies gained will enable us to eliminate the need for almost 90% of our meter readers, or about 160 employees. Installation will begin in June and be complete by the end of 2006. For customers, this technology will result in a less-intrusive meter reading process, more accurate and timely bills, and fewer estimated bills. This initiative, while requiring an initial capital outlay, will reduce on-going O&M expenses to an even greater degree over time and will serve as a platform for further operational efficiencies and capabilities in the future.

Q. Please provide an overview of the distribution O&M program that the Company is proposing in this proceeding.

A. PEF forecasts that it will spend $126.1 million in distribution O&M costs in 2006. Included in this amount is $18.7 million in O&M associated with twelve specific incremental initiatives necessary to preserve our reliability gains and broaden and re-balance our reliability focus for customers, as described in my testimony above. These programs, which will fund an increasingly aggressive posture on refurbishing and replacing equipment before it fails, as well as the implementation of several system improvements to deliver the described benefits, are outlined in Exhibit No. ___ (DM-2).

Also included in this amount is distribution O&M savings of $3.5 million associated with the Company's current reorganization. The Company is undertaking a complete review of its organizational structure in order to once again identify areas where further efficiencies can be achieved. This initiative, which will be implemented throughout 2005 and will include employee incentives for voluntary early retirement, is expected to produce almost $20 million in O&M savings in 2006, with roughly $3.5 million in the area of distribution. These savings result from our constant focus on improving efficiency, eliminating redundancies through centralization where appropriate, and ensuring the maximum use of our resources.

Finally, the figures above include an adjustment to reclassify $30.0 million of outage and emergency activities from capital to O&M due to an accounting change. The Company reviewed its capitalization policies for its Energy Delivery business units. The review indicated that in the areas of outage and emergency work not associated with major storms and allocation of indirect costs, PEF should revise the way it estimates the amount of capital costs associated with such work. As a result of this change, a lesser portion of these costs will be capitalized on a prospective basis and a correspondingly higher portion will be charged to O&M expense. This accounting adjustment is discussed in further detail in the testimony of Robert Bazemore and Javier Portuondo.

Q. Are the distribution costs proposed for 2006 reasonable?

A. Yes. As I have described above, the Company has worked diligently to ensure that we are focused on the right priorities, our budgets are reasonable, and we are spending our money wisely. We have demonstrated this through our strong results in industry benchmarking, both from an operational and cost performance perspective. These results are described in the testimony of Bill Habermeyer, Jeff Lyash, Dale Oliver and in my own comments above. As mentioned above, the Company is currently undertaking a complete review of its organizational structure in order to once again identify areas where further efficiencies can be achieved and has incorporated the expected savings into our rate request. Excluding the impact of the change in accounting discussed above, our forecasted 2006 distribution O&M expenses are within $0.5 million (or within one percent) of the Commission's O&M benchmark established in our last rate case (as adjusted for customer growth and inflation). This includes our proposed incremental reliability spending and reflects the significant cost pressures described in my testimony. Our budget for 2006 represents the right balance of costs and service level for our customers.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF

WILLETTE MORMAN-PERRY

I. Introduction.

Q. Please state your name, position, and business address.

A. My name is Willette Morman-Perry. I am the Director of Customer Service for Progress Energy Florida ("PEF" or the "Company"). My business address is 5225 Tech Data Drive, Clearwater, Florida 33760.

Q. What are your duties and responsibilities?

A. I am responsible for serving Progress Energy Florida's 1.5 million customers in the areas of customer billing, collections of revenue, call center operations, web applications, voice response unit systems, and payment operations.

Q. Please describe your educational background and work expertise?

A. I have over 24 years experience with Progress Energy in Customer Service including work as a project analyst, supervisor, and as manager of Call Services. I began my career at Progress Energy as a clerk in a field office and from there transitioned to a Customer Service Associate position in the pilot of the centralized customer service center. Among other assignments, I also served as a Training Analyst for Employee Development, as Project Analyst to centralize customer service functions for Carolina Power & Light Company ("CP&L"), as well as Project Analyst in support of the Customer Service Integration Project for the North

Carolina Natural Gas Company acquisition and the Customer Service Integration Project for the acquisition of Florida Progress. I have a bachelor's degree from North Carolina Wesleyan College.

II. Purpose and Summary of Testimony.

Q. What is the purpose of your testimony?

A. I appear on behalf of Progress Energy Florida to discuss the Company's strategy for continuing to provide and enhance customer service and to support the reasonableness of expenses in that area.

Q. What schedules in Progress Energy Florida's MFRs do you sponsor?

A. I sponsor or co-sponsor schedules C-11, C-37, C-38, and C-39, insofar as they relate to customer accounts and customer service. These schedules are true and correct, subject to their being updated in the course of this proceeding.

Q. Please summarize your testimony.

A. The Company is dedicated to anticipating and meeting the needs of its customers by effectively utilizing technology and resources to improve responsiveness and customer satisfaction. We are aware that our customers are increasingly demanding greater convenience and more accessibility, which we are providing through Web-based services, electronic billing, Voice Response Unit ("VRU") operations, additional payment locations, and prompt customer service response.

We believe the initiatives we are budgeting will enable us to provide the type of service that our customers expect and have grown accustomed to.

III. Customer Accounts.

Q. Please provide an overview of expenses for customer accounts.

A. We are forecasting to spend $36.9 Million in 2006 for customer accounts expense. It is important to note that this spending level is based on a $13.8 million savings achieved through the synergies obtained through the implementation of our Mobile Meter Reading program.

Our 2006 budget amount is expected to decrease the O&M benchmark amount of $59.9 Million by $22.9 Million. The budget includes labor costs and other costs of operating our customer information system, including the initiatives that I describe herein.

Q. What customer service improvements have you implemented to minimize costs and increase services provided to your customers?

A. We have implemented a number of initiatives which have better enabled PEF to anticipate and fulfill evolving customer expectations, such as:

New Software/Increased Web Enablement. We have implemented software that enables our customer service representatives to resolve billing inquiries during the initial customer contact. This allows the representative to analyze the customer's bill on the spot and to compare it directly with recorded temperatures for the customer's specific area. Also, new applications are available on the internet to allow our customers to complete requests on line.

The Company has also invested in building a website dedicated to our customers. In 2003, "Customer Registration" was implemented, which offers customers web applications such as: (1) connect and disconnect requests and analysis of usage history; (2) a "Builders Express" website; (3) receipt validation; (4) credit arrangements; (5) a "Multifamily Housing" (rental property owners) website; (6) name and phone number update; (7) seasonal rate registration; (8) a "report a street light repair" feature; (9) duplicate bill requests; (10) a "Lower My Bill" toolkit; (11) OpinionLab (survey/comments); (12) a "find a payment location" feature; and (13) electronic funds transfer registration. Our Web application is now more robust, and we have placed emphasis on moving additional functionality to the Web to give all customer segments increased access to information and greater choices in how they do business with us.

Combined Customer Service. Progress Energy Carolinas and PEF have combined their customer service organizations in order to maximize knowledge and management oversight, and to provide a consistent, customer-focused approach to the management of customer service. This combination allows for more effective use of resources in the development of training programs and system and Web application upgrades. It also allows PEF to leverage the combined needs of the two companies to procure more advantageous contracts with outside vendors for collections, outage reporting, and payment management. This situation is invaluable during major storm events because each of the customer service centers can provide additional resources to help manage peak call volumes for the other.

Work process improvements. PEF continually reviews work processes to look for efficiencies. Under this initiative, projects such as "One Call Resolution" were initiated. As we know from customer feedback, one call resolution plays a big part in customer satisfaction. Through our "One Call Resolution," program, we strive to resolve customer calls upon the first contact, thereby avoiding the need for call backs.

New technologies. Call management systems in Florida were integrated with Carolina systems in early 2002. This integration facilitated improved sharing of resources, statistical reporting, and call-type tracking and performance monitoring. This integration also reduced the resource requirements for handling inbound customer phone calls. This new technology allows for improved outage reporting, improved access to restoration information, and enhances PEF's automatic outage call back system.

In mid-2001, a new vendor system was implemented that allows 125,000 additional telephone calls per hour on a 24 hours per-day basis. This system allows for increased call capacity for our customers in major storm events.

Enhancements to Bills. During 2002, the Company instituted a bill redesign. Through this initiative, several improvements to our customer bills were made, such as a graph on the bill, payment location phone numbers, and a "pay by credit card" phone number. The addition of this information to our customer bills has increased customer satisfaction. This has been validated as

PEF has ranked in the first quartile in Billing and Payment in J.D. Powers & Associates surveys the last two years.

Although we have accomplished quite a bit over the last couple of years to improve service to our customers, we are committed to continuous improvement. With this, we will continue to leverage and improve our use of technology. For 2005, PEF plans receipt validation reconnection, posting agency pledges, improvements to our outage script and call back feature, and multi-account activity, all via the VRU. In addition, we continue to look for ways to improve our customer web site through such initiatives as automated budget billing sign up, which we expect to roll out by year end 2005.

Q. What does Progress Energy Florida do to monitor customer satisfaction levels?

A. PEF closely monitors customer satisfaction levels to ensure we are meeting the needs of our customers. We use a variety of methods to gather satisfaction levels such as: "Fastrack", "Customer Experience Monitor", executive office complaints, focus groups, Florida Public Service Commission ("Commission")) complaint data, and external benchmarking.

PEF measures the performance of Customer Service Center associates through call monitoring. Recently, we kicked off an initiative called BCL (Building Customer Loyalty) that expands our monitoring process to focus on key behaviors to maximize customer satisfaction. BCL enables employees to fully understand how their behavior impacts unit, department, group, and organizational goals. External measures we use are Fastrack and the Customer Experience Monitor which are independent customer surveys. Specifically, Fastrack measures customer satisfaction as it relates to a recent contact with the Company. The Customer Experience Monitor measures overall perception of the Company. In addition, focus groups have been conducted on an ad hoc basis as another touch point with our customers. Commission data is also analyzed to identify trends in customer issues. These customer touch points enable PEF to quickly identify customer issues through our root cause analysis process and identify action plans to increase satisfaction. Benchmarking tools such as J.D. Powers & Associates surveys are another important component used to measure our performance against our competitors and with industry standards. I am proud to share that PEF ranked number one in the 2004 J.D. Powers & Associates Customer Service component for the Southern Region. J.D. Powers also ranked Progress Energy 3rd in the South Region for Business Customer Satisfaction.

Recently, Progress Energy was named as one of the electric companies offering the best overall customer service in 2004. The award was presented during the eighth annual Customer Service Awards program at the Edison Electric Institute's (EEI) Spring National Accounts Workshop. Progress Energy was named a winner of the 2004 Utility Awards for marketing and customer service efforts by the Energy Planning Network's Utility CIS/CRM Consortium. This recognition placed Progress Energy as one of eleven winners worldwide for having the best CIG (commercial, industrial, governmental) programs for investor-owned utilities.

Q. Are the Company's expenditures for customer service cost-effective and reasonable?

A. Certainly. We are very pleased with the success of our efforts in this area. We are providing superior customer service and we are an industry leader in offering automated technology. Since the merger, our resource sharing capabilities enhanced service to our customers at lower costs. Again, leveraging our economies of scale and maximizing our resources has allowed us to provide superior service while reducing our costs.

Q. Does this conclude your testimony?

A. Yes it does.

DIRECT TESTIMONY OF
ROBERT H. BAZEMORE, JR.

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is Robert H. Bazemore, Jr. My business address is Accounting Department, Progress Energy Service Company, LLC, P.O. Box 1551, PEB 18A1, Raleigh, North Carolina 27602.

Q. By whom are you employed and in what capacity?

A. I am the Vice President and Controller for Progress Energy, Inc. ("Progress Energy") and Progress Energy Florida, Inc. ("Progress Energy Florida") and Vice President in charge of Accounting for Progress Energy Service Company, LLC ("Service Company").

Q. What are the duties and responsibilities of your positions with respect to Progress Energy Florida?

A. As Vice President and Controller of Progress Energy and Progress Energy Florida, I am responsible for all accounting and financial reporting functions (both internal and external) for Progress Energy and its subsidiaries, including Progress Energy Florida. I oversee accounting policies and procedures, accounting business controls, and accounting records. Apart from Progress Energy Florida, Progress Energy's subsidiaries include Progress Energy Carolinas ("PEC") and Progress Energy's other regulated and non-regulated businesses.

Q. Please describe your educational background and professional experience.

A. I earned my Bachelor's Degree in Accounting in 1976 at the University of South Florida. From 1976-1978, I worked as a Staff Accountant for Smoak, Davis & Nixon in Jacksonville, Florida. From 1978-1980, I worked as a Senior Accountant with Main Hurdman in Jacksonville. From 1980-1983, I was a Supervisor for Ernst & Whinney in Roanoke, Virginia. I was promoted to Senior Manager in 1984 and served in that capacity until 1986. I moved to Carolina Power & Light ("CP&L") in 1986 as Manager of Financial and Contract Auditing in the Audit Services Department until 1991. From 1991-1995, I worked as the Controller for CP&L's Harris nuclear power plant. From 1995-1998, I served as Manager of Financial and Regulatory Accounting in CP&L's Accounting Department. I became Director of the Operations and Environmental Support Department of CP&L in 1998, and served in that position until 2000, when I took my current position as Vice President and Controller of Progress Energy. I am a Certified Public Accountant ("CPA") licensed in Florida and North Carolina and a Certified Internal Auditor. I am also a member of the American Institute of CPA's and of the North Carolina Institute of CPA's.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the reasonableness of the Administrative and General ("A&G") portion of the Company's Operation and Maintenance ("O&M") expenses as well as depreciation and asset retirement obligations.

Q. Do you have any exhibits to your testimony?

A. Yes, I have supervised the preparation of the following exhibits to my direct testimony:

- Exhibit No. ___ (RHB-1), a list of the Minimum Filing Requirements (MFRs) schedules I sponsor or co-sponsor.
- Exhibit No. ___ (RHB-2), the SEC Order approving the Service Company's organizational structure and cost allocation methodologies, dated November 27, 2000.
- Exhibit No. ___ (RHB-3), the Service Company's Cost Allocation Manual.
- Exhibit No. ___ (RHB-4), the May 8, 2003 SEC Audit Letter.
- Exhibit No. ___ (RHB-5), the Service Company's Organizational Chart.
- Exhibit No. ___ (RHB-6), the Actuarial Study supporting the Pension Credit.
- Exhibit No. ___ (RHB-7), the AUS Consultants' 2005 Depreciation Study.

All of these exhibits are true and accurate.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements (MFRs)?

A. Yes, I sponsor the MFR schedules identified in Exhibit No. ___ (RHB-1), and they are true and accurate, subject to their being updated in the course of this proceeding. For example, as I explain in more detail below, the Company continues to look for ways to control costs and operate more efficiently. The Company has undertaken an enterprise-wide review of its organization to identify areas where further operational efficiencies can be achieved to produce additional cost savings. This initiative is being implemented throughout 2005 and into 2006 and includes employee incentives for voluntary early retirement as positions are eliminated under the reorganization. The reorganization initiative, including the initial estimate of cost savings net of reorganization expenses from the initiatives that were not available when the 2005 and 2006 budgets were prepared, is explained in more detail in the testimony of Javier Portuondo.

Q. Please summarize your testimony.

A. The A&G functions for Progress Energy Florida are performed primarily through the Service Company. The Service Company was formed and approved under the Public Utility Holding Company Act of 1935 ("PUHCA"). The Securities and Exchange Commission ("SEC"), as directed in the PUHCA, reviewed and approved the creation, policies, and cost allocation methodologies of the Service Company. The Service Company complies with the SEC rules regarding the operation of a subsidiary service company. In particular, the SEC rules require the Service Company to provide services efficiently and economically "at a cost fairly and equitably allocated among" operating subsidiaries. Progress Energy's cost-allocation program is designed to ensure that all costs are allocated fairly and equitably and that one company will not subsidize another.

Administrative and General Expenses consist primarily of corporate benefit costs, human resources, finance, corporate communications, legal, regulatory affairs, corporate services (e.g. facilities, procurement), information technology ("IT"), and telecommunications. In order to effectively benchmark from Progress Energy Florida's last base rate proceeding, we believe it is appropriate to exclude "Pension & Benefits" and the Storm Damage Reserve from the benchmark. The Pension and Benefit expenses are subject to market forces beyond the Company's control since health care costs are rising rapidly and far exceed the Consumer Price Index ("CPI"). Pension expense is subject to fluctuations due to pension investment returns based upon the portfolio of investments. Changes to the Storm Damage Reserve are also beyond the Company's control and heavily influenced by the 2004 hurricane season. Progress Energy Florida has forecasted that its A&G O&M expenses for 2006 are within the Florida Public Service Commission ("Commission") benchmark from the last base rate proceeding, excluding Pension and Benefit expenses and the Storm Damage Reserve. Progress Energy Florida has managed and controlled A&G expenses without sacrificing customer service or reliability. In fact, the Company has achieved Company-wide improvements in the quality of customer service and in reliability.

Additionally, the Company has filed its 2005 Depreciation Study with the Commission. This Study is a fair representation of the Company's efforts to recover its plant costs. The net effect is an annual depreciation decrease of $46.6 million across all property functions.

II. <u>Overview of the Service Company</u>.

Q. Who administers A&G functions for Progress Energy Florida?

A. Progress Energy provides A&G functions for all of its subsidiaries in a centralized manner through Progress Energy Service Company. Progress Energy formed and operates the Service Company in strict compliance with the PUHCA and the rules and regulations of the SEC with the oversight by the SEC. Under the PUHCA, the SEC is charged with the responsibility for regulating subsidiary service companies of utilities subject to PUHCA, like our Service Company.

Q. How does SEC regulation of the Service Company under PUHCA affect Progress Energy Florida?

A. Under PUHCA, a registered holding company may not sell services or goods to its subsidiaries directly, but only through an authorized mutual or subsidiary service company. The SEC must, therefore, approve the organization of subsidiary service companies, like Progress Energy Service Company, that are formed to centralize various management and administrative functions. In its order attached as Exhibit No. ___ (RHB-2) to my testimony, the SEC approved the Service Company's organization and structure.

Section 13(b) of PUHCA also limits the amount that a subsidiary of a registered holding company may charge when it renders services or sells goods to any other company in the holding company system (i.e., any associate company) to such subsidiary's "cost," fairly and equitable allocated among all associate companies. Likewise, the SEC's rules require, among other things, that the Service Company provide services efficiently and economically "at a cost fairly and equitably allocated among" operating subsidiaries. Rule 88(b), 17 C.F.R. § 250.88(b). To implement this rule, the SEC has prescribed a uniform system of accounts for service companies modeled on those prescribed by the Federal Energy Regulatory Commission ("FERC") for electric utilities. All service company charges must be limited to its "cost" of performing such services. The categories of services that a service company may perform and all cost allocation methods must be pre-approved by the SEC. Any modification in the categories of services provided or methods of allocation used by a service company must also be approved by the SEC.

Progress Energy's cost-allocation program is designed to ensure that all costs are allocated fairly and equitably and that one company will not subsidize another. Progress Energy's policies, procedures, methodologies, and metrics are described in detail in Exhibit No. ___ (RHB-3), the Cost Allocation Manual for Progress Energy Service Company. This Manual was prepared by the Progress Energy Service Company for its use when supplying various administrative, management, and corporate support services to the regulated and non-regulated associate companies within the Progress Energy holding company system. The Manual includes the description of services and allocation methods used by Progress Energy Service Company. As described in Exhibit No. ___ (RHB-2), the SEC has approved the Service Company's cost allocation methodologies.

After a service company is established, and its organizational structure and cost allocation methodologies are approved, the SEC continues to monitor all financing activities, intercompany cost allocations, and affiliate transactions to ensure that all processes, methodologies, and policies support the full and equitable allocation of service company costs to all associate companies (including the holding company), both regulated and non-regulated. For example, Progress Energy Service Company must file an annual report (on Form U-13-60), providing significant detail about its operations and cost allocations. Progress Energy Service Company filed its first annual report for the year 2001 on May 1, 2002, and has subsequently filed annual reports each May for 2002 and 2003, and will file its annual report in May for the year 2004. The SEC also conducts periodic audits of our Service Company. The SEC audited Progress Energy

Service Company with the resulting closure of the examination indicated in Exhibit No. ___ (RHB-4). In connection with the SEC audit, the Staff of the Florida Public Service Commission (the "Commission") was invited to participate and did in fact participate in the audit. Finally, the SEC requires Progress Energy to maintain an active role in evaluating the Service Company's compliance with PUHCA through its internal audit functions.

Q. How is the Service Company organized?

A. Please see Exhibit No. ___ (RHB-5). This is an organization chart for Progress Energy Service Company that identifies the Service Company's functions.

Q. Please give a brief overview of the products and services provided by Progress Energy Service.

A. The Service Company provides processing, reporting, and management oversight for a variety of areas, including finance, insurance, IT, real estate and facility services, procurement, corporate communications, human resources, audit services, environmental, legal, and regulatory. Exhibit No. ___ (RHB-5), the Service Company organizational chart, provides a listing of all Service Company departments and Exhibit No. ___ (RHB-3), the Cost Allocation Manual, provides a detailed listing of all Service Company products and services.

Q. How do Progress Energy Florida's customers benefit from the Service Company?

A. The Service Company consolidates various corporate functions and eliminates duplicative resources, thus, reducing the cost of utility operation to the utility's customer. The Service Company provides centralized management of finance, insurance, IT, real estate and facility services, procurement, corporate communications, human resources, audit services, environmental, legal, and regulatory. This integration has allowed the combined companies to reduce the number of redundant functions where staffing levels are relatively fixed and do not vary directly with an increase or decrease in the number of employees or customers. Progress Energy Service Company is also able to lower costs by integrating many previously separate programs, including employee benefits, investor services, fleet systems, travel programs, purchasing practices, facilities management, security, and insurance. The centralization of management further improves the quality of operations through, among other things, the incorporation of common work practices and shared best practices among the companies. All of these attributes of the Service Company inure to the benefit of Progress Energy Florida's customers by providing greater efficiency in utility operations and, thus, lower costs than would otherwise be the case.

Q. Please describe the cost allocation methodologies employed by Progress Energy Service Company.

A. The costs of the Service Company are classified into various products. Each functional area has several products within it. Prior to allocating costs, the Service Company will assign or charge directly to an affiliate those costs associated with a product that specifically benefits a particular affiliate or that a particular affiliate causes the Service

Company to incur. For example, if Progress Energy Service Company performs an IT project for Progress Energy Florida or incurs costs to improve Progress Energy Florida's vehicle fleet, Progress Energy Service Company will assign the costs of these projects (or "products") directly to Progress Energy Florida.

Any costs that are not directly attributable to a particular affiliate are allocated to the various affiliates that use the service or product based on SEC-approved metrics. These metrics are basically objective formulas for allocating costs per customer, per square foot, per invoice, or on such other basis as may be appropriate to the kind of cost, service, or product involved. Progress Energy Service Company evaluates and updates its metrics at least once every year.

In addition to allocating costs of products and services that Progress Energy Service Company itself provides to various affiliates, including Progress Energy Florida, the Service Company provides direction and oversight to ensure that each Progress Energy subsidiary fairly and equitably allocates costs among the appropriate affiliates, using uniform cost-allocation principles. Regardless whether shared functions and services are managed directly by Progress Energy Service Company or are operated through other Progress Energy subsidiaries with cost allocation oversight by the Service Company, Progress Energy's entire cost-allocation program has been designed to guard against the subsidization of one entity at the expense of others.

The policies, procedures, methodologies, and metrics are described in detail in Exhibit No. ___ (RHB-3), the Cost Allocation Manual for the Service Company.

III. <u>Administrative and General ("A&G") Expenses</u>.

Q. As the sponsor of Progress Energy Florida's MFRs detailing the A&G O&M justification schedule, please provide an overview of Progress Energy Florida's performance in this area.

A. We believe that Progress Energy Florida continues to perform well in the area of A&G O&M expenses, taking into account and separately considering those A&G O&M items that are primarily driven by market forces beyond the Company's reasonable control, such as the Pension Credit, the substantial increases in the costs of health care benefits for employees, and the increase in the Storm Damage Reserve. The 2002 test year was a transition year for the Service Company with implementation of many new systems and processes. The transition to a merged company with a fully functional service company was on-going. Using this test year as the Commission benchmark, and adjusting for customer growth and inflation, the Company's 2006 A&G budget is within the Commission benchmark, excluding Pension & Benefits and the adjustment to the Storm Damage Reserve, i.e. $137.1 million budget versus $140.7 million benchmark. This demonstrates that the Company has successfully held the line on A&G O&M costs except for certain expenses, most notably, pension costs, and employee health care costs that are rapidly increasing at a rate in excess of the consumer price index ("CPI") used by the Commission in its benchmark, and the Storm Damage Reserve, due to the impact of significant weather events.

Q. Why are there significant variances within the A&G FERC accounts compared to the benchmark?

A. We have applied the benchmark to each A&G O&M FERC account consistent with prior Commission practice of applying it to the 2002 actual results in MFR Schedule C-6. The total A&G O&M expenses are within the Commission benchmark for total A&G O&M costs, excluding Pension & Benefits and the Storm Damage Reserve as noted above. The Commission benchmarks are a tool to assist the Commission to understand what factors affect the Company's O&M expenses and to evaluate the appropriate level of the Company's O&M expenses. They are not, without consideration of the reasons for any reported variance, determinative of the reasonableness of any particular A&G O&M expense. In our case, the benchmark of total A&G O&M expenses against the Company's total A&G O&M expenses in the 2006 test year, excluding "Pension & Benefits" and the Storm Damage Reserve for reasons more fully developed below, is the most appropriate benchmark to understand the Company's A&G O&M expenses.

To explain, the MFRs in the last rate proceeding were based on a 2002 test year. Calendar year 2002 was a key year for integration of the merged companies. It was the first year that new Florida financial systems went into service, that Service Company allocations were fully automated, and consistent practices were implemented. Calendar year 2002 was, therefore, a transition year as the Company and the Service Company continued to learn the systems and develop consistent practices across FERC accounts. We have determined that in a number of instances costs charged to one FERC account in the 2002 MFRs should have been charged to different FERC accounts to be consistent with the 2006 MFRs. The result is that a number of variances in the comparison of the individual A&G expenses by FERC account in the current MFRs to the Commission benchmark are the result of reallocating costs among the FERC accounts. This reallocation of cost issue is mitigated when you look at the total A&G expenses for all of the FERC A&G accounts. Therefore, the comparison of the total A&G O&M expenses in the current MFRs to the Commission benchmark at the total A&G O&M expense level gives a clearer picture of the Company's A&G O&M expenses, (taking into account the effects of customer growth and inflation, as intended by the Commission benchmark).

Q. What is the Storm Damage Reserve?

A. The Storm Damage Reserve is an unfunded reserve for all direct costs not covered by insurance for certain storms. Since Hurricane Andrew in 1992, the Company has been self-insured for storm damage to its transmission and distribution system. Pursuant to Commission Order No. PSC-94-0852-FOF-EI in Docket No. 940621-EI, the Company is accruing $6 million annually in base rates to the Storm Damage Reserve based on a study the Commission requested from the Company and approved.

Q. Why is there a variance in the MFRs for the Storm Damage Reserve?

A. The Storm Damage Reserve was fully depleted by the 2004 hurricane season. The costs to the Company to prepare for and respond to four hurricanes far exceed the balance in the Storm Damage Reserve. The Company commissioned an updated study in 2004 to determine what the annual accrual to the Storm Damage Reserve should be. Based on that Study, the Company has determined that the annual accrual should be an additional $44 million, or a total of $50 million a year. The $44 million additional annual accrual represents the variance in the MFRs compared to the Company's last base rate proceeding. A copy of the Company's updated study is an exhibit to the testimony of Javier Portuondo.

Q. Turning to the line items in the A&G justification schedule, please explain the variance projected for the "Pension Credit" and why you believe this cost item should be considered separately from other A&G costs.

A. There is an unfavorable benchmark variance reported in the MFRs for the Pension Credit of approximately $20.8 million. This item, along with other expenses associated with employee benefits and the Storm Damage Reserve, represents the majority of the unfavorable variance reported in the MFRs.

The Pension Credit is determined using actuarial studies prepared by a third party actuarial firm. A copy of the most recent actuarial study is attached to my testimony as Exhibit No. ___ (RHB-6). As discussed more fully below, the Pension Credit is determined pursuant to the provisions of the Financial Accounting Standards Board, Statement No. 87 Employers' Accounting for Pensions. The Commission approved the use of FAS 87 for ratemaking purposes in Docket No. 910890-EI, Order No. PSC-92-1197-FOF-EI (October 22, 1992). Under these guidelines, a credit may be reflected when the expected return on plan assets exceeds our service cost and other components of pension expense. The Pension Credit can fluctuate due to several factors, the most significant of which are the market performance of the investments held in the pension plan and the discount rate. Customer growth and the CPI have no impact on the calculation of the Pension Credit. As a result, the Commission benchmark, which adjusts all O&M expenses in the MFRs by the same factors of customer growth and inflation, is not reflective of the factors that cause increases or decreases in the Pension Credit.

For example, in the Company's last base rate proceeding we reported a favorable benchmark variance of $42.6 million in the Company's MFRs, which with the agreement of the Commission, were filed before the testimony. That was subsequently updated by the time I filed my testimony to a favorable benchmark variance of $19.5 million due to market performance of the underlying pension investments. The $23 million change in the variance represented updated actuarial forecast results reflecting the decline in the stock market in 2001. To judge changes in the Pension Credit by customer growth and the CPI, as the Commission benchmark does, in no way captures those forces affecting changes in the value of the Pension Credit. The Commission benchmark, then, is not an appropriate mechanism to evaluate changes in the Pension Credit.

Q. Please discuss the unfavorable variance described as Health Benefits Costs.

A. Another driver behind the unfavorable benchmark variance is the cost of health benefits for the Company's employees. Applying the Commission O&M benchmark and adjusting only for growth and the CPI, the unfavorable variance between the 2006 MFRs and the O&M benchmark is approximately $7.1 million. Coupled with the unfavorable benchmark variance for the Pension Credit explained above, the total unfavorable variance of the Pension Credit and Health Benefits costs is approximately $28 million.

Q. Do you believe that the O&M benchmark accurately reflects the experience with health care costs?

A. No, I do not. The O&M benchmark uses the CPI to escalate costs and therefore assumes that all O&M costs will increase at the same rate. This may be a reasonable assumption for some O&M costs but it is not appropriate for health care costs, which are escalating at a rate that far exceeds the CPI. This is true not only for Progress Energy but for all businesses and individuals.

It is well documented in publications, national news, and the subject of political forums, that health care costs are escalating at double digit rates. Progress Energy's health care costs have increased at an average growth rate of 12% since 2002.

The Company is always looking for opportunities to manage and contain the growth in health care costs while also maintaining competitive health care benefits. Since 2002, the Company has taken aggressive cost management actions that include adding a three-tiered co-pay to our prescription drug plan to encourage generic utilization; annually adjusting employee contributions; eliminating two high-cost HMOs; introducing income-based medical premiums; and increasing the level of communications to employees to educate them on how to improve their health and concurrently mitigate health care cost. We have also implemented a disease management program to facilitate the effective medical treatment of plan participants with specific diseases that, if not properly managed, can generate expensive claim costs.

Progress Energy's health care costs are also consistent with the national trends. For example, the overall cost of health care per plan member for a Progress Energy employee and their covered dependents is $2,998 compared to $3,330 for other companies based on a recent national survey of health care plan costs by Mercer.

The Company has done a very good job controlling health care costs in a climate where all businesses are struggling to balance increasing benefit costs with offering competitive, value-added employee benefit plans.

Q. Can you please explain the unfavorable benchmark variance involving the shift of IT costs from FERC functions outside of A&G?

A. Yes, I can. This variance is an example where the reallocation of costs among FERC accounts skews the results of the Commission O&M benchmark test. From 2002 to 2006, the methodology used to charge telephone circuit costs was modified to achieve more accurate cost allocation and to facilitate better management of actual circuit usage, and the addition of new circuits. This resulted in a movement of costs from functional FERC accounts to A&G FERC accounts. Within A&G, this created a $7.4 million unfavorable variance compared to the Commission benchmark. There is a favorable variance in other FERC functions (outside of A&G) as a result of this change of $6.6 million. The net result is a $0.8 million unfavorable variance primarily due to Progress Energy Florida's telephone circuit costs. However, IT costs overall to Progress Energy Florida, considering all FERC functions, is favorable by $4.6 million.

Q. Why do you show an unfavorable benchmark variance of about $6 million in FERC account 925, "Injuries and Damages," in the A&G justification schedule?

A. The increase in FERC account 925, which contains insurance expenses, is primarily due to an increase in nuclear, liability, and workers' compensation insurance. In the nuclear insurance area, nuclear property is insured through Nuclear Electric Insurance Limited

("NEIL"). NEIL is a mutual insurance company whereby the member's cost is typically reduced by distributions as a result of excellent industry performance and investment returns in underlying assets. The test year budget for nuclear insurance is unfavorable by $4 million compared to the benchmark due to a decrease in distributions from NEIL. The NEIL distributions are lower because of fluctuations in its investment market performance.

Executive liability insurance is unfavorable compared to the benchmark by $1.5 million due primarily to market conditions and the reaction of the Directors' and Officers' liability insurance industry to corporate scandals such as Enron. Other liability and workers' compensation insurance also increased compared to the benchmark based on market conditions affecting the price of insurance and continuing impacts from 9/11 events.

Q. Let's turn now to the favorable variances in the A&G justification, please discuss the efficiencies represented by the Service Company cost changes outlined in the MFRs.

A. Comparing the MFRs in 2002 to the MFRs in 2006, we have achieved approximately $16 million of A&G cost efficiencies and reductions in work scope before offsets compared to the Commission benchmark. These savings are from many different areas of the Service Company. For example, the separate combination of disparate Corporate Communications and Finance groups among the companies resulted in significant efficiencies in the operations with a lower overall cost to the customer.

The savings are partially offset by increases in depreciation expense and incentive charges. The higher depreciation expense is due to the growth in the Service Company's technology assets as a result of the integration of the Florida system. This integration of technology has been a significant enabler to the Service Company in achieving cost efficiencies in other areas. There is an unfavorable variance to the benchmark of $5.9 million related to incentives. This is driven by differences in payout level between 2002 actuals (on which the benchmark is based) and the test year, as well as accounting adjustments in 2002. These variances are partially offset by the reclass of some incentives from A&G to other FERC functions between the benchmark and the test year. The increase in incentive payouts in 2006 compared to 2002 relates to company performance. The incentive payouts are tied to the number of goals achieved in a given year. Goal achievement was at a lower level in 2002, but, with the Company-wide improvements in all areas of service quality and our plan to maintain those advancements in service quality, we expect higher achievement levels in the 2006 budget. Other witnesses for the Company will explain in detail our movement to the top quartile in our industry in customer service, reliability, and safety, among other improvements. The incentive payments are a critical part of our continued commitment to excellence. To maintain the commitment, and provide quality service, we must reward our employees for doing a great job.

Even with these offsets, we still achieved significant efficiencies and cost reductions in A&G compared to the Commission's benchmark.

Q. Are Progress Energy Florida's total projected A&G O&M expenses for 2006 reasonable?

A. Yes. In an era of rapidly escalating health care costs we have otherwise held the line on our costs at the level we committed to as a result of the merger. Excluding "Pension & Benefits" and the resulting impact of market forces outside of our control and rising health care costs, and the uncontrollable severe weather impacts on the Storm Damage Reserve, our total A&G expenses are representative of the Commission benchmark. We believe this demonstrates that we have operated efficiently and in a cost-effective manner.

Moreover, all costs are allocated on a fair and equitable manner to Progress Energy Florida in compliance with PUHCA and under the ongoing oversight of the SEC. The Service Company engages in rigorous cost control, subjecting proposed expenditures to close scrutiny, internal challenge, and active management oversight. The Company has taken and continues to take appropriate steps to control A&G costs while providing competitive compensation and benefits to employees.

Q. Are there any other changes in the 2006 test year that will have an impact on the Company's capital and maintenance expenses?

A. Yes, there is. The Company has reviewed its capitalization policies for its Energy Delivery business units. That financial consistency review indicated that in the areas of outage and emergency ("O&E") work not associated with major storms and the allocation of indirect costs, PEF should revise the way that it estimates the amount of capital costs associated with such work. The Company has implemented such changes effective

January 1, 2005, that include more detailed classification of outage and emergency work. As a result of the changes in accounting estimates for the outage and emergency work and indirect costs, a lower proportion of PEF's costs will be capitalized on a prospective basis. This change in accounting methodology is also explained in the testimony of Javier Portuondo.

Q. What is the impact on the 2006 test year due to the change in accounting methodology?

A. The Company estimates that the combined effect of the change in the character of the costs in the O&E account will result in approximately $34 million of additional O&M costs being expensed in the test year.

IV. <u>Depreciation and Asset Retirement Obligations</u>.

Q. Please describe the Company's implementation of the FASB Statement No. 143.

A. Effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations ("AROs")," to account for legal obligations associated with the retirement of certain tangible long-lived assets. The present value of retirement costs for which the Company has a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The liability is then accreted over time by applying an interest method of allocation to the liability.

The Company recognized an asset retirement obligation for the nuclear decommissioning of irradiated plant at Crystal River 3 ("CR3"). The asset retirement costs related to CR3, net of accumulated depreciation, totaled $36 million with an associated obligation of $337 million at December 31, 2004. The Company also identified but did not recognize AROs related to electric transmission and distribution and telecommunications assets as the result of easements over property not owned by the Company. These easements are generally perpetual and only require retirement action upon abandonment or cessation of use of the property for the specified purpose. The ARO liability is not estimable for such easements because the Company intends to utilize these properties indefinitely. In the event the Company decides to abandon or cease the use of a particular easement, an ARO liability would be recorded at that time.

The adoption of this statement had no impact on the income of the Company, as the Commission issued an order to authorize deferral of all effects, initial and prospective, related to SFAS No. 143. Therefore, SFAS No. 143 has no impact on the income or expense of the Company.

The Company also recognizes certain removal, decommissioning, and dismantlement costs. These amounts are components of depreciation expense, recorded as accumulated depreciation for regulatory purposes, and are supported by Commission approved studies. For financial reporting purposes these amounts are classified as regulatory liabilities in accordance with SFAS No. 143 and SFAS No. 71. At December 31, 2004, these costs consist of removal costs of $1,005 million, removal costs for non-irradiated areas at nuclear facilities of $61 million, and amounts previously collected for dismantlement of fossil generation plants of $144 million.

Additionally, in April 2003, the FERC issued Order No. 631 (Docket No. RM02-7-000), "Accounting, Financial Reporting and Rate Filing Requirements for Asset Retirement Obligations." In the Order the FERC added new balance sheet accounts to record the liability and the related asset, new income statement accounts to record accretion of the liability and the depreciation of the related asset, and updated as necessary the definitions, general, and plant instructions contained in the Uniform Systems of Accounts. The FERC also revised certain schedules in its Annual report (FERC Form No. 1). The Company has complied with these requirements.

Q. Has the Company filed a new Depreciation Study with the Commission?

A. Yes, it has.

Q. Who prepared the new Depreciation Study and on what principle is it based?

A. Progress Energy Florida engaged the services of Earl Robinson, Certified Depreciation Professional of AUS Consultants, a Division of Weber Fick & Wilson, to perform the 2005 Depreciation Study. The Study was prepared in accordance with Commission Rule 25-6.0436, F.A.C. The Study contains the results of the depreciation analysis of its actual depreciable plant as of December 31, 2003. Depreciable plant balances were estimated as of December 31, 2005. These estimates are based upon PEF's 2005 forecasted plant balances. The estimated plant balances were used to compute the change in depreciation expense between this Study and PEF's 1997 approved depreciation study. Exhibit No. ___ (RHB-7) to my testimony is a true and accurate copy of the 2005 Depreciation Study.

Q. Please summarize the depreciation impact by functional area in the Study.

A. Applying the proposed depreciation parameters to the Company's estimated plant in service balances at December 31, 2005 compared to the 1997 approved rates, and allocating the retail depreciation credit, the Study produces annual depreciation decreases of $ 46.2 million. A summary of the property functions with decreases are: Steam ($ 24.4 million); Nuclear ($ 16.5 million); Other Production ($ 1.1 million); Transmission ($ 12.1 million); and General Plant ($.2 million); offset by an increase in Distribution of $ 8.1 million.

Q. Please describe the factors by function that result in the change in depreciation expense in the 2005 Depreciation Study.

A. The factors that influence depreciation expense are different by function. The decrease in Steam is primarily driven by lower net book values in the 2005 Depreciation Study as compared to the 1997 Study, being depreciated over generally similar average remaining lives. Additionally the total amount estimated for cost of removal decreased resulting in lower annual cost of removal expense.

The decrease in Nuclear is primarily driven by assuming a 20-year life extension at the Crystal River 3 plant ("CR3"), resulting in a decrease in the overall annual depreciation expense.

The decrease in Other Production is primarily driven by the addition of the Hines 3 plant offset by the extension of the depreciable life at the Hines 1 plant from 20 years to 30 years, which results in a slight decrease in overall annual depreciation expense.

The decrease in Transmission is primarily driven by longer depreciable lives primarily for Account 353.20 – Station Equipment, Account 355 – Poles and Fixtures and Account 356 – Overhead Conductor and Devices. Additionally, Account 353.20 is forecasted to have a significantly lower net book value in the 2005 Depreciation Study.

The increase in Distribution is primarily driven by an increase in the total amount estimated for cost of removal for Account 364 – Poles and Fixtures. This is partially offset by longer lives and lower total estimated cost of removal for Account 365 – Overhead Conductor and Account 368 – Line Transformers and longer lives for Account 373 – Street Lighting and Signal Systems, which is partially offset by increases in removal costs for this type of property.

Q. Are there any major plant additions that will impact the 2006 test year and ultimately the depreciation expense to the Company?

A. Yes, there are. As noted above, the Company plans for an extension of its operating license for the Company's nuclear generation unit, CR3. This will extend the life of CR3 to 2036, yielding an expected decrease in the annual depreciation expense. Also, the Company will be extending the life of its Hines 1 combined cycle generating unit from 20 to 30 years, and expects a resulting decrease in the annual depreciation expense for the unit.

In addition, the Company will be adding to rate base the addition of the Hines 2 combined cycle generation unit, which achieved commercial operation in December 2003. The Company will also be adding the Hines 3 combined cycle generation unit to its generation system in December 2005. This additional generation unit is also reflected in the 2006 test year, along with all generation additions to that point in time. The result is an increase in the depreciation expense to account for this new generation.

Q. Does the 2005 Depreciation Study take into account the termination of the depreciation credit described in the settlement of the last rate proceeding in Docket No. 000824-EI?

A. Yes, it does. As outlined in Order No. PSC-02-0655-AS-EI, approving the settlement in the Company's last rate proceeding, the Company suspended accruals for nuclear decommissioning and fossil dismantlement. For each calendar year during the period of the rate settlement, the Company recorded $62.5 million as a credit to depreciation expense and a debit to the depreciation reserve. At its option, the Company could record up to an equal annual amount as an offsetting accelerated depreciation expense and a credit to the depreciation reserve. The Company did not elect this option and as a result will have accumulated a debit to the depreciation reserve of $250 million as of December 31, 2005.

The Order states that any such reserve amount will be applied first to reduce any reserve excesses by account, as determined in the 2005 Depreciation Study. Table 5F – Future (Pro Forma) of the Study compares the theoretical reserve to the estimated book reserve at December 31, 2005. As shown on Table 5F – Future (Pro Forma) of the Study, the Company proposes to allocate the $250 million to reserves where the December 31, 2005 book reserve exceeds the theoretical reserve using the percent of the excess over the total reserves with excesses multiplied by the reserve balance. This amount was then further allocated to the December 31, 2005 plant, salvage, and cost of removal reserves. The impact of this allocation was to increase estimated annual depreciation expense going forward by approximately $13 million. This increase is factored into the functional increases and decreases discussed above and the proposed depreciation rates in the Study.

None of the $250 million debit to the bottom line reserve was allocated to reserve deficiencies.

The Company emphasizes that the overall decrease in annual depreciation expense being proposed in the Study is a fair representation of the Company's effort to recover its plant costs. This decrease also reflects the addition of the plant at Hines 3, increased investment in the Transmission and Distribution areas, and the increased depreciation expense from the depreciation credit.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF

JOHN B. CRISP

I. Introduction and Purpose.

Q. Please state your name and business address.

A. My name is John B. Crisp, and my business address is Progress Energy, Inc. ("Progress Energy"), P. O. Box 1551, Raleigh, North Carolina 27602.

Q. By whom are you employed and in what position?

A. I am employed by Progress Energy Carolinas as the Director of System Resource Planning.

Q. Please describe your duties and responsibilities as they relate to Florida.

A. My responsibilities include the development and implementation of energy system expansion plans and generation asset optimization plans for Progress Energy Carolinas and Progress Energy Florida ("PEF" or the "Company"). These expansion and optimization plans, otherwise known as integrated resource plans ("IRPs"), include detailed review and analysis of system load forecasts, and the corresponding determination of supply-side and demand-side resources available to meet the load requirements identified in the system load forecasts. The supply side and demand side resources include assets currently available on the existing system, and assets potentially available to the Company over its planning horizon.

These analyses result in recommended action to the Company's management for asset changes or additions that fulfill the Company's obligation to serve.

Q. Please summarize your educational background and employment experience.

A. I attended the Georgia Institute of Technology in Atlanta, Georgia, where I received a Bachelor of Science degree in Industrial and Systems Engineering in 1979. After working for a defense department contractor, my power industry employment began in 1988, when I joined Oglethorpe Power Corporation. Since 1988, I have worked for both regulated and non-regulated utilities in a variety of management positions. My responsibilities have included the management of power plant construction, generation plant operations, system dispatch, load and energy forecasting, integrated resource planning, and energy and fuels marketing. During my non-regulated utility tenure I implemented generation asset and portfolio optimization alliances through commercial marketing arrangements to sell excess generation capacity and energy.

In May 1999, I joined Florida Power Corporation as its Director of Integrated Resource Planning and Load Forecasting. Along with the supervision responsibility for demand side management programs and integrated resource planning, I directly supervised the group responsible for developing the Florida Power Corporation load and energy forecast. Following the creation of Progress Energy Corporation, which was a result of the merger of Florida Power Corporation and Carolina Power & Light, I assumed my current responsibilities as the Director of System Resource Planning for Progress Energy's regulated utilities. In this role and in previous roles, I have provided testimony to several different state utility regulatory bodies, including the Florida Public Service Commission ("FPSC" or the "Commission"), on issues involving load forecasts and the most effective means for utilities to meet their obligation to serve the respective load forecast.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the development and results of PEF's load forecast used in the preparation of this rate case. As I use the term "load forecast" in my testimony, I intend for it to include the Company's individual projections of customers, energy sales, and coincident peak demand.

Q. Have you prepared any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of several exhibits, as follows:

- Exhibit No. ____ (JBC-1), a list of the Minimum Filing Requirements (MFRs) schedules I sponsor or co-sponsor.
- Exhibit No. ___ (JBC-2), Customer, Energy Sales & Seasonal Demand Forecast.
- Exhibit No. ____ (JBC-3), Forecast Process Flow Chart.
- Exhibit No. ____ (JBC-4), PEF Short Term Forecast Performance Review.
- Exhibit No. ____ (JBC-5), PEF Energy and Customer Forecasting Models.
- Exhibit No. ____ (JBC-6), PEF Historical Forecast Accuracy.

- Exhibit No. ___ (JBC-7), U.S. & Florida Economic Assumptions – 2002 – 2006.
- Exhibit No. ___ (JBC-8), PEF Historic & Projected Growth Rates.

These exhibits are true and accurate.

Q. What Minimum Filing Requirements ("MFRs") schedules do you sponsor?

A. I sponsor all or portions of the MFR schedules identified in Exhibit No. ____ (JBC-1). I have reviewed them and they are true and accurate, subject to being updated during the course of this proceeding.

II. <u>Load Forecast</u>.

Q. What is the purpose of a load forecast?

A. In order to serve its customers in a cost-effective and reliable manner, PEF must estimate or project how much energy its customers (old and new) will consume in the future and when that consumption is likely to take place. The load forecast enables the Company to do just that. Specifically, the load forecast allows the Company to estimate into the future the likely number of customers it will serve, the amount of electric energy it will sell to those customers, and the time(s) at which the customers demand for electric energy will be greatest. PEF then uses this forecast in both its planning and budgeting process.

Q. Does the Company prepare more than one type of load forecast.

A. The Company normally prepares two forecasts each year. One is a long-range, ten-year trend forecast that is used for resource planning studies and other similar purposes. The second forecast is a shorter (typically five-year) forecast that takes into account current business and economic conditions. This forecast is used for developing the revenue forecast and for short-term financial planning. In a rate case such as this, the Company's five-year forecast serves as the basis for the development of the MFRs.

Q. When was the forecast utilized in this case developed?

A. The forecast used for this filing and for the development of the 2005 and 2006 budget years was completed in July 2004 and is titled "July 2004 Short Term Forecast - Customers - Sales - Demand." It is a five year (2004-2008) projection that seeks to capture the short-term impacts of economic and demographic fluctuations in Florida and the nation upon customer, energy sales, and peak demand growth. The Company's forecast of customers, energy sales, and demand for the test year (2006) is reflected in Exhibit No. ____ (JBC-2).

III. <u>Forecast Methodology</u>.

Q. Would you please give us an overview of the methodology used to develop the load forecast?

A. Yes. As reflected in Exhibit No. ___ (JBC-3), there are four main steps in the development of a load forecast: the assembly of the forecast assumptions, the derivation of forecast model parameters, the calculation of the forecast, and adjustments to the forecast based upon the educated judgment of the forecaster.

• **Assembly of the Forecast Assumptions.** The first step in any forecasting procedure is to assemble a set of assumptions upon which the forecast is based. The assumptions describe the forecaster's educated prediction about how the future will unfold with respect to influences upon company energy sales, customer growth, and system peak. In developing these assumptions, the forecaster relies in part on the opinions of professional economists at Economy.Com, the University of Florida's Bureau of Economic and Business Research ("BEBR"), as well as other sources. Each of these groups develops forecasts of national and regional economic and demographic data. These forecasts are purchased by the Company. Some of the assumptions are derived from historical data like normal weather conditions. The assumptions utilized in the July 2004 forecast are set forth in Schedule F-8 of the MFRs. It is important to note that in all cases the assumptions made are based upon a "most-likely" forecast. Forecasted values of these forecast assumptions become inputs to the forecast models that lead to customer, energy and peak demand projections.

• **Derivation of Forecast Parameters.** Next, based on the assumptions, the forecaster derives the parameters for the forecast model. The parameters of a forecast model quantify the statistical relationship between the economic and demographic environment impacting a utility service area and the latest energy usage (and customer growth) patterns of its customers. These parameters are updated each time a forecast is produced to ensure that the resulting forecasts reflect current energy consumption patterns in the Company's service territory.

For example, there are typically twelve months of additional "actual" data between each short-term forecast. Thus, each short-term forecasting model will incorporate this additional information along with any additional economic data reported since the previous short-term forecast was produced. In addition, when deriving model parameters the forecaster incorporates (to the extent possible) historical data from the ten most recent years into the model sample

• **Development of the Forecast.** The forecaster then proceeds to develop the new forecast. The Company's load forecast actually consists of three separate forecasts as follows:

- a customer forecast
- an energy sales forecast
- a coincident-peak demand forecast (primarily used for resource planning purposes)

Customer forecast – The Company's customer forecast (i.e., the number of customers it expects to serve during the forecast period) is developed primarily from county population projections produced by the University of Florida's Bureau of Economic and Business Research. In a service area like PEF's, where nearly 98.4 percent of the Company's customers are residential and commercial customers, these population projections serve as the best predictor of the Company's total customers. This is because an increasing service area population translates directly into a greater number of homes and commercial establishments to service these homes. An annual econometric model is used to measure the historical relationship between service area population and residential customer growth. The resulting parameter becomes a "multiplier" that, when applied to the population growth forecast, results in a projection of new residential customers. Once the residential customer forecast is finalized, it is used as the "driving" variable in the commercial customer regression model. The customer forecasts for the remaining retail sectors are forecast using trend analysis because of their relatively stable historical patterns.

In producing the customer forecast, the Company also reviews the performance of the current forecast in light of the latest actual data available. This permits us to evaluate the performance of the Company's most recent forecast to aid in the development of its new forecast. For the November 2003 forecast, a comparative analysis was performed in January 2005. As shown in Exhibit No. ___ (JBC-4), the November 2003 Short-Term Forecast of customers is compared to actual year-to-date results through December 2004. In this case, the system customer count was 0.54% percent higher than forecast for the year. This variance may be explained in part by historically low mortgage rates that have remained lower than expected. Nonetheless, based on this variance, the Company adjusted its customer growth rate upward in preparing the July 2004 forecast used in this proceeding.

Energy Sales Forecast – The Company's energy sales forecast is developed using monthly econometric models. These short-term models project monthly energy sales by revenue class (residential, commercial, industrial, street lighting and public authority) and require the forecaster to have a thorough understanding of each variable to be projected (i.e., residential customer growth or average residential use per customer) and the influences or events that create monthly variation or movement in those variables. Sales are regressed using "driver" variables that best explain monthly fluctuations over a sample period. For example, in order to project average KWh energy usage per customer, driver variables such as weather and economic conditions are utilized to capture the statistical relationship to changes in kWh consumption per customer. This approach enables the forecaster to incorporate the most recent historical data as well as the most current outlook on the economy. The modeling specifications for each retail class energy model (and residential and commercial customer models) are set forth in Exhibit No. ___ (JBC-5).

The result of this customer and energy sales forecast is shown in Exhibit No. ____ (JBC-2). This forecast is the basis for the development of the revenue forecast that is incorporated into the Company's budgeting process and serves as the basis for the 2006 revenue forecast in this rate proceeding. Two additional procedures are required before the final billing determinants are created for input into the Company's financial model. The first procedure transforms the monthly energy forecast from a "billing month" basis to a "calendar month" basis. This involves forecasting the amount of "unbilled retail energy" in a calendar month and allocating it down to each retail revenue class. The forecast of monthly retail unbilled energy is derived using ten years of historical monthly averages of "billed energy generated in prior month" divided by "total billed in current month". Each retail class receives its respective share of total retail unbilled energy sales according to the percentage share it makes up of total retail billed month energy sales.

The second procedure required to finalize the billing determinants takes the calendar month revenue class energy and customer projections and disaggregates them to the major rate class level. This is made possible by determining the revenue class to rate class proportions for the most recent calendar year available (2003). Allocating the forecast to this more detailed level allows monthly revenues to be generated in the PEF revenue model. For rate classes that have a "billing KW" charge as part of its billing determinant, a historic load factor is also developed at this time which, when applied to the rate class projection of energy, derives the class projection of billing KW. Customer, energy and billing KW projections are shown in MFR E-15.

Coincident Peak Demand Forecast – The coincident peak demand forecast (used for resource planning as opposed to revenue forecasts) is developed using a disaggregation technique followed by econometrically modeling several of the disaggregated components. The disaggregation technique separates monthly system demand into four major components: potential firm retail demand, nondispatchable and dispatchable direct load control (MW) capability, sales for resale demand, and Company use. Each of the peak demand components is then separately forecast and added arithmetically to the next or, in the case of demand side management ("DSM"), subtracted, to arrive at total system firm peak demand.

- **Forecaster's Judgment.** Finally, after all of the parts of the load forecast are complete, the forecaster evaluates the cumulative modeling results and makes adjustments as appropriate based on his or her professional judgment as well as such adjustments as may be reasonably necessary to capture the impact of events that the model is unable to capture.

For example, econometric models develop parameters ("beta coefficients") that are applied to projections of "driver" variables that are purchased from an economic forecasting firm and may be three or more months old. Occasionally, economic events unfold very rapidly and sometimes out-of-date projections are used in the models. Even historical economic data get revised by government agencies and can paint a picture that differs subtly from what is reflected in the original economic data. When this occurs, the forecaster will incorporate the latest information he or she understands is influencing company sales or customer growth levels. Other times, events such as rate migrations may require special adjustments to the rate schedule level forecast that cannot possibly be captured by an econometric model.

IV. <u>Forecast Performance</u>.

Q. Historically, how accurate has the Company's forecast been of customers and energy sales when compared to actual data?

A. In order to respond to this question, I conducted a study of the Company's accuracy in forecasting customers and energy sales, which is presented in Exhibit No. ____ (JBC-6). In this study, I included every forecast used in PEF's corporate budget since 1990. As shown on Exhibit No. ___ (JBC-6), I compared each year's actual retail energy sales and customer data to the budget projection made during the prior year. For example, actual 1990 retail sales of 24,878 GWh are compared to the forecast completed in 1989 which projected 25,087 GWh for 1990. The percent forecast variance is shown for each year. A review of the 15-year period 1990-2004, shows that the average forecast error was a respectable -0.39 percent with the year 2004 variance at -2.2 percent (-1.3 percent adjusting for Hurricane impacted lost sales). The magnitude of the energy sales variances as measured by the mean absolute percent error ("MAPE") for the 15-year period is 1.87 percent. A similar review of the retail customer forecast at Sheet 2 of Exhibit No. ___ (JBC-6) reveals an average forecast variance over the past 15 years (1990-2004) of +0.08 percent. The MAPE of these customer forecasts is an exceptional 0.53 percent.

At bottom, this study shows that the Company is forecasting customers and energy sales very accurately. Notably, as reflected in the Commission's Staff Review of Florida Utilities 2004 ten-year site plans, the Company's energy sales forecast accuracy for the period considered in Staff's study out-performed all but one Florida utility on an average absolute forecast error basis with a score of 0.62 percent versus the nine utility average of 1.40 percent. (See "A Review of Florida Electric Utility 2004 Ten Year Site Plans - Table 3.)

V. <u>July 2004 Forecast Summary</u>.

Q. Can you briefly summarize the conclusions to be drawn from PEF's July 2004 load forecast?

A. Yes. Based on the July 2004 forecast, PEF expects that its customer base, energy sales, and peak demand will grow at similar growth rates as the Company has experienced in the recent past. While the Company has experienced an abnormally high rate of customer growth in 2003-2004 – driven in part by 46-year lows in mortgage interest rates – the forecast calls for a more normal level of net new customer growth in 2005 and 2006 as interest rates rise and demand for housing subsides. The Federal Reserve Board had increased interest rates five times in 2004 with the goal of stabilizing rates at higher levels typical of periods with normal economic expansion. This is expected to keep the economy from overheating and igniting inflationary pressures. It has been stated that this policy will continue through 2005.

This slowdown is not reflected in the projected energy sales growth rate, however. As just previously mentioned, the U.S. economy is returning to a more normal rate of expansion and this is expected to drive energy sales accordingly. A list of U.S. and Florida economic variables with historic and projected growth rates is shown in Exhibit No. ___ (JBC-7). Several of these economic series call for higher average rates of change over the 2005 to 2006 period than experienced over 2002 and 2003. PEF weather normalized retail energy sales reflect this same pattern. The two-year growth rate (2002-2003) of retail energy sales was 5.6 percent while the expected increase in energy sales for 2005-2006 is 6.7 percent. The main assumption underlying this optimism is a return to higher job growth. Coincidentally, forecasted rates of change for both U.S. and Florida residential building permits were expected to fall drastically in 2004 and again in 2005 reinforcing my pessimism for the Florida housing market. PEF historic and projected growth rates for weather normalized billed sales and customers are shown in Exhibit No. ___ (JBC-8).

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY OF
MARK A. MYERS

I. Introduction and Purpose.

Q. Please state your name and business address.

A. My name is Mark A. Myers. My business address is 410 S. Wilmington Street, Raleigh, North Carolina 27601.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC ("Service Company"), in the capacity of Vice President, Corporate Planning.

Q. What are the duties and responsibilities of your position?

A. As Vice President for Corporate Planning, I am responsible for strategic planning, financial planning and forecasting, business planning, budgeting and corporate development for Progress Energy.

Q. Please describe your educational background and professional experience.

A. I am a graduate of Florida State University, holding a degree of Bachelor of Business Administration, Accounting Major. In addition, I hold a Master of Business Administration from the University of Tampa. I joined Florida Power Corporation in 1983 as a financial auditor. Since then, I have held various management positions, including vice president of finance for Progress Energy Florida. Beginning in 2005, I became vice president of corporate planning. In addition to my work experience, I am a licensed certified public accountant in the state of Florida, a chartered financial analyst, and a certified internal auditor.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present and explain the budgeting and financial forecasting process regularly employed by Progress Energy Florida ("PEF" or the "Company") for corporate planning purposes and used in this proceeding to develop the Company's detailed "per books" income statement and balance sheet information for 2005 and the 2006 test year, which provides the foundation for the Minimum Filing Requirements (MFRs) submitted by PEF in support of its rate relief request. I will also describe the procedures used by the Company to monitor and control, and to update when necessary, its Operation and Maintenance (O&M) and Construction budgets after they have been put into effect. Finally, I will present the key assumptions for, and the significant components of, the Company's 2005 and 2006 budgets.

The testimony of Mr. Javier Portuondo will address the use of the 2005 and 2006 budget information to produce the "per books" figures contained in PEF's MFRs, as well as the ratemaking and other regulatory adjustments to the per books figures necessary to derive the test year revenue requirements and resulting revenue shortfall upon which PEF's rate relief request is based.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits which are attached to my direct testimony:

- Exhibit No. _____ (MAM-1), a list of the schedules I sponsor in the Company's MFRs.
- Exhibit No. _____ (MAM-2), 2005 and 2006 Key Budget Assumptions.

These exhibits are true and correct.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements (MFRs)?

A. Yes, I will sponsor the MFR schedules listed in Exhibit No. __ (MAM-1). These schedules are true and accurate, subject to their being updated in the course of this proceeding.

II. <u>Corporate Planning and Budgeting Process</u>.

Q. Would you please provide an overview of the Company's corporate planning and budgeting process?

A. Certainly. Normally, we plan and budget on a two year basis -- planning in 2004, for example, for the business years 2005 and 2006. We conduct this process throughout the course of the year in several stages. We begin by engaging in a review of strategic and corporate objectives for the coming year. Then we set financial targets for business units, taking into account the resource needs of each of the Company's business units and the corporate objectives we have established for the coming year. Next, the business units develop business plans and budgets calculated to achieve these targets. Once these are completed, we integrate them into an overall corporate plan and budget. Finally, this is reviewed, modified as may be appropriate, and approved by senior management and the Board.

The development of the budget and corporate plan is a dynamic process that involves the interplay of strategic planning, ongoing re-examination and adjustment of historical spending levels, continuous energy and sales forecast updating, rigorous review of resource needs and operational constraints, and target setting designed to drive performance and control costs and to ensure that any additional outlays for capital projects or O&M expenditures are necessary and cost-effective.

Q. Please describe the corporate operating budget and how it is developed.

A. The corporate operating budget includes all the components that comprise our annual profit plan, such as revenues, fuel and non-fuel expenses, O&M, taxes, etc. This is to be distinguished from the business unit O&M budget, which addresses the Company's period costs by functional areas, *i.e.*, power production, operations (transmission, distribution, and customer services), and Administrative and General expenses. The corporate operating budget includes the business unit O&M and Construction budgets. The corporate operating budgeting process begins in July with the conclusion of the financial target setting process. Business unit O&M and construction budgets are developed over a four month process running concurrently with the corporate operating budgeting process. Diligent coordination with various corporate departments is necessary to ensure an end-product that is cohesive and accurate.

Q. Would you explain the development of the significant components of your corporate operating budget for 2005 and 2006?

A. Yes. The budget of revenues is based on the most recent customer, load, and energy sales forecast and is integrated into the Company's corporate financial model (the "Model"). The Model is a computer simulation application used to forecast monthly and annual financial data through the use of a number of integrated calculation modules. The Model is updated on a timely basis to include the most current rate data as well as the approved corporate customer, sales, and demand forecast. The Model then calculates base revenues. Other revenue components, such as fuel, energy conservation, and franchise fees, are then computed to develop the total operating revenue projection. The fuel cost projection requires multiple inputs before a projection can be developed. First, a forecast of fuel prices by fuel type is prepared by the fuels department and is reviewed by senior management. The budgeted fuel cost forecast is incorporated as an input to the Company's production simulation model, known as PROSYM, along with numerous other factors associated with the load and operating characteristics of our generation system. PROSYM simulates the most economical dispatch from the Company's generating system to calculate fuel consumption and replacement fuel costs. This data is transferred as inputs to the Model. This is the same process used to generate the Company's annual fuel adjustment filing.

The O&M budget development is exclusive of fuel costs recoverable through the fuel adjustment clause. Managers develop a detailed operating plan for the budget year. From this operating plan, a preliminary budget is developed on a project/FERC/resource basis. This budget represents the base line for which the manager is held accountable during the upcoming year. The budget reflects the manager's goals and objectives to be justified to successive levels of management. The individual budgets are consolidated at various levels within each business unit to create a preliminary corporate budget. At the conclusion of the preliminary review and analysis, each department's detailed budget is input into the corporate budget system. Each department inputs its direct expenditures, and then a series of burdens and allocations are run. These include benefit and tax burdens on payroll, inventory burdening, and sales and use tax burdening on materials and allocation of Service Company costs to business units. Other adjustments are made to the budget for certain corporate level expenses and accruals, such as the nuclear outage, pension costs, and nuclear joint-owner credits.

Q. How are allocations from Progress Energy Service Company handled in the budget process?

A. The costs of the Service Company are classified into various products. We assign or charge directly to an affiliate those costs associated with a product that specifically benefits a particular affiliate or that a particular affiliate causes the Service Company to incur. Any costs that are not directly attributable to a particular affiliate are allocated to the various affiliates that use the service or product based on SEC-approved metrics.

Regardless of whether shared functions and services are managed directly by Progress Energy Service Company or are operated through other Progress Energy subsidiaries with cost allocation oversight by the Service Company, Progress Energy's entire cost-allocation program has been designed to guard against the subsidization of one entity at the expense of others. The testimony of Mr. Bazemore provides a more detailed discussion of Service Company allocations.

Q. Please provide a brief overview of the Company's construction program from a planning perspective.

A. The capital budget process begins with the development of initial targets that are based primarily on prior year budget estimates, most recent resource plans, and corporate financial objectives. The business units then conduct a thorough analysis of their capital requirements and prepare a preliminary capital budget. This information is reviewed and approved by the Company's Regulated Capital Committee, a cross-functional team of senior executives. The approved plans are incorporated into PEF's financial forecast. Senior management makes changes to the capital forecast as required to meet operational and financial objectives.

The foundation of the construction program and, in turn, the Construction Budget, is the need for the physical facilities required to provide electrical energy to our customers. Examples of the types of facilities are generating units, transmission lines and substations, and distribution substations and structures. The need for these facilities is generally based on customer growth projections, age and technological obsolescence of existing plant, availability of alternative energy sources such as purchased power and qualified facilities, demand-side management programs, and system reliability and qualitative considerations. A number of detailed studies are performed in which various alternatives are evaluated based on reliability, costs, and fuel type. The end result of these studies is a specific plan for construction of generating facilities of specific size, at specified points in time, including related transmission and distribution facilities. The essential construction requirements data included in this plan are then transmitted to the various construction management groups who develop the detailed Construction Budgets.

Q. What are the review and approval procedures for the O&M and Construction Budgets?

A. The O&M and Construction Budgets receive several levels of review and approval that begin at the individual manager level. The first review is conducted by the manager in each area. Each individual budget is then rolled up to the next level of management for review until ultimately they are reviewed by the senior management within each business unit. The senior management in each business unit evaluates the budgets in conjunction with the operational goals and objectives that have been established for that business unit and the spending limits that have been established. The business unit level budgets are submitted to Corporate Planning for consolidation into the corporate forecast. The business unit submissions are reviewed for consistency with targets and alignment with the corporate financial goals and objectives.

If the consolidated corporate O&M and Construction Budgets reflect proposed spending levels above the approved corporate guidelines, senior management will meet to consider the merits of funding certain activities or programs based on overall corporate, rather than departmental, considerations. The conclusion may be a deferral or scope reduction in some activities or programs. Once the proposed consolidated O&M and Construction Budgets conform to the corporate guidelines, the individual budgets are revised, resubmitted, and re-examined by each departmental executive to assure consistency with the respective spending level contained in the consolidated O&M Budget. The final O&M Budget as compiled by the budgets department and endorsed by senior management is presented to the Board of Directors for approval.

Q. How does the Company monitor and control the O&M and Construction Budgets after they have been put into effect?

A. The primary means used to monitor and control the O&M and Construction Budgets is through the monthly Cost Management Reports (CMR). These reports reflect monthly and year-to-date variances by business unit and are distributed to senior management as part of the Company's monthly corporate financial report. Cost management reports also include current year projections of O&M and capital spending compared to annual budgets. These projections are the basis for updated corporate income and cash flow projections, which are presented to senior management monthly and to the Board of Directors quarterly.

Q. What are the key assumptions used by the Company in preparing its budgets for 2005 and 2006?

A. The key assumptions underlying the 2005 and 2006 budgets are listed in my Exhibit No. ___ (MAM-2), 2005 and 2006 Key Budget Assumptions and MFR Schedule F-8.

Q. What are the 2005 and 2006 operation and maintenance (O&M) and construction budgets for PEF's Distribution, Transmission, Production, Customer Services, and Administrative and General (A&G) functional areas that resulted from the budget process you have described?

A. The following is a breakdown of the Company's 2005 and 2006 O&M and construction budgets for the five functional areas. PEF's witnesses for these functional areas will address and support the specific components of the O&M and construction budgets for their respective areas.

Distribution	O&M	Construction
2005	$ 77,636,000.	$216,506,000.
2006	$ 80, 873,000.	$211,253,000.
Transmission	O&M	Construction
2005	$ 27,609,000.	$ 64,324,000.
2006	$ 27,647,000.	$ 77,829,000.
Production	O&M	Construction
2005	$196,841,000.	$188,862,000.
2006	$210,597,000.	$196,807,000.
Customer Services	O&M	Construction
2005	$ 56,494,000.	$ N/A
2006	$ 58,901,000.	$ N/A
A&G	O&M	Construction
2005	$205,131,000.	$ 245,000.
2006	$211,751,000.	$ 130,000.

Q. Have there been any adjustments to these 2005 and 2006 budget amounts?

A. Yes. There have been several adjustments to these budget based "per books" amounts that are discussed in the testimony of other witnesses. These adjustments include the Company's reorganization initiative, mobile meter reading initiative, distribution and transmission reliability initiatives, charging practices accounting change, and Storm Damage Reserve accrual. Preliminary estimates of the net cost savings or impacts of some of these changes or initiatives, like the reorganization initiative, were not available until early this year. Others, like the Storm Damage Reserve and the distribution and transmission reliability initiatives, reflect efforts to prepare the Company to meet the impacts of future storms and the growing priority our customers place on greater power reliability that have not yet been approved by the Commission. Mr. Portuondo and Mr. Lyash, Mr. DeSouza, and Mr. McDonald, respectively, provide full explanations for the latter two adjustments in their testimony.

Q. Does this conclude your direct testimony?

A. Yes.

DIRECT TESTIMONY OF

THOMAS R. SULLIVAN

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is Thomas R. Sullivan and my business address is 410 S. Wilmington Street, PEB 19A3, Raleigh, North Carolina, 27601.

Q. What is your position with Progress Energy Florida?

A. I hold the position of Treasurer at Progress Energy Florida, Inc. ("PEF" or the "Company"). I am also Vice President – Treasurer and Chief Risk Officer of Progress Energy Service Company.

Q. Would you please briefly outline your qualifications and professional experience?

A. I came to Carolina Power & Light Company as Manager – Financial Operations in November 1997 and was later promoted to Vice President and Treasurer of Progress Energy. I am responsible for all capital raising activities for Progress Energy and its subsidiaries. As Treasurer and Chief Risk Officer, I have responsibility for Financial Operations, Corporate Insurance, Financial Analysis and Enterprise Risk Management. Prior to joining Carolina Power & Light Company, my seventeen years of business experience included serving as Director - Treasury Capital Markets at Visa International Service Association, Assistant Treasurer of LB Credit Corporation, various financial positions within Signal Capital Corporation, and fixed income analyst at Liberty Mutual Insurance Company.

I have a bachelor's degree from St. Lawrence University and a master's degree in business administration from Northeastern University.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the capital structure of PEF and the impact long-term purchase power contracts (PPAs) have on our financial policy. The treatment of these contracts by the rating agencies affects financial ratios, in particular leverage ratios, used to determine a company's credit rating. As Treasurer, it is my responsibility to maintain PEF's capital structure in a manner which supports our target credit rating, therefore I must take into consideration the adjustments a rating agency may make when developing its financial ratios to assess its credit rating.

Q. Do you have any exhibits to your testimony?

A. Yes, I have the following exhibits to my direct testimony:

- Exhibit No. ______ (TRS-1), *Credit Implications of Power Supply Risk*, Moody's Special Comment, July 2000.
- Exhibit No. ___ (TRS-2), *Standard & Poor's Research: "Buy versus Build": Debt Aspects of Purchased-Power Agreements*, May 8, 2003.
- Exhibit No. ___ (TRS-3), *Fitch presentation to Progress Energy*, October 2003.

These exhibits are true and accurate.

Q. What is your target credit rating for PEF?

A. The long-term target credit rating for PEF is single A for its senior secured and unsecured debt.

Q. How many rating agencies perform credit analyses on Progress Energy Florida?

A. Three rating agencies, Standard & Poor's Rating Service, Moody's Investor Service and Fitch Ratings, provide credit ratings for PEF.

Q. What is the current credit rating for PEF?

A. The following table summarizes the credit ratings for PEF for each of the three major rating agencies which currently rate PEF's debt.

	S&P	Moody's	Fitch
Senior Unsecured	BBB	A3	BBB+
Senior Secured	BBB	A2	A-

Q. Why is it important for PEF to obtain an "A" rating from all three rating agencies?

A. Investors distinguish between companies with split ratings versus companies who have the same rating across all rating agencies. The lower rating in a split-rated company will result in a higher cost of debt for that company.

Q. Why do you target "single A" as PEF's long-term debt rating?

A. A strong credit rating assures PEF access to low-cost debt during both good and difficult capital market conditions. PEF, like other electric utilities, has the obligation to serve its customers. This obligation requires access to the capital markets under all market conditions. In other words, the flexibility surrounding the timing of a security issuance for a regulated electric utility can be limited. Unlike nonregulated companies, PEF cannot easily change the timing of its capital spending, and therefore the timing of security issuances. These commitments are driven in large part by its obligation to serve, a 20% reserve margin requirement, and ever growing environmental compliance requirements. This requires that PEF be able to issue low-cost debt securities during all market conditions.

Q. How do these rating agencies treat long-term power supply contracts when evaluating a company's credit profile?

A. While each one's specific method may vary, they all base their analysis on the premise that long-term fixed payments associated with these contracts are essentially debt-like in nature, much like a long-term lease on property, plant, and equipment. The following excerpts from the three rating agencies' public statements illustrate this consistent view among the agencies:

MOODY'S

"Moody's will continue to view these off-balance sheet obligations as debt – in particular those purchased power obligations that are above market." Credit Implications of Power Supply Risk, Moody's Special Comment, July 2000. Exhibit No. ___ (TRS-1)

STANDARD & POOR'S

Standard and Poor's Ratings Service (S&P) views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these *obligations on a sliding scale known as a "risk-spectrum." S&P Research: "Buy versus Build": Debt Aspects of Purchased-Power Agreements.* May 8, 2003. Exhibit No. ___ (TRS-2)

FITCH

For purchased power agreements, operating leases, tolling arrangement, and synthetic leases, Fitch policy varies from GAAP accounting rules in order to capture operating leverage. Fitch presentation to Progress Energy, October 2003. Exhibit No. ___ (TRS-3). S&P, who actually makes a numerical adjustment to PEF's ratios, recently modified its methodology. (See Exhibit No. ___ (TRS-2)). Under S&P's approach, future capacity payments are discounted using a 10% discount rate. The net present value of those payments is multiplied by a risk factor, the result of which is the amount of imputed debt included in certain financial ratios, including its adjusted leverage ratio. For PEF, S&P uses a risk factor of 30%. S&P will also impute an amount for interest expense associated with the imputed debt by multiplying the imputed debt amount by 10%. This amount is included in interest coverage ratios.

Q. What is the impact on a company's credit profile when rating agencies treat long-term power supply contracts as debt-like?

A. The main effect is that a company is considered to have more leverage than if you calculated its leverage ratio based only on the debt recorded on its balance sheet.

Q. Does PEF have long-term power supply contracts?

A. Yes, PEF has a substantial amount of purchase power commitments relative to its total generation mix. As of December 31, 2004, PEF had 489 MWs of purchased power with other utilities and 821 MWs with certain cogenerators (QFs).

Q. What is the basis for S&P's risk factor adjustment?

A. As stated in S&P's article "*Buy versus Build*" the overriding factor influencing the risk factor is the likelihood of payment by the buyer. It notes that the probability of nondelivery by independent generators is quite low, thus the probability of a buyer having to pay for purchased power, is quite high. Given the high likelihood of payment by the buyer, these long-term fixed obligations are assigned a higher risk factor for purposes of imputing debt. S&P states that PPAs are viewed as a fixed commitment and when a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk.

S&P's generic guideline for utilities with PPAs of over three years is to use a 50% risk factor. According to S&P, the risk factor "assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. S&P does view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant." Exhibit No. ___ (TRS-2).

Q. Do you agree with S&P's use of a 30% risk factor for calculating imputed debt for PPAs?

A. I agree with the concepts underlying S&P's methodology. By entering into long-term PPAs, you are entering into a long-term fixed commitment, which is debt-like in nature.

However, I don't think S&P has given the appropriate recognition to the unique circumstances surrounding PEF's regulatory treatment of these contracts, which is very important in determining the appropriate risk factor. On February 24, 2005, we discussed with S&P our views regarding the use of a 30% risk factor. We stated, among other things, that the strength of the regulatory recovery clauses in place to recover capacity payments associated with these contracts did not support a 30% risk factor. To my knowledge, S&P has not changed their position on this issue and until they do, we must consider their calculation for imputed debt when assessing PEF's capital structure.

Q. How much debt and interest expense does S&P impute when assessing the impact of PPAs on PEF's credit ratios?

A. As of December 31, 2004, the present value (using a 10% discount rate) of PEF's future capacity payments for its QF and utility PPAs was approximately $2.7 billion. S&P then computes the amount of imputed debt by applying a 30% risk factor for PEF, which results in approximately $806 million of imputed debt. S&P would impute $80.6 million of additional interest expense based on an assumed interest rate of 10%.

Q. Does this amount change each year?

A. Yes, assuming we do not enter into any other PPAs, the amount of imputed debt is projected to decline over time as the termination date of the contract approaches.

Q. What is S&P's impact on PEF's capital structure when imputing debt associated with long-term PPAs?

A. The following table shows PEF's projected capital structure for year- end 2006. Off-balance sheet (OBS) obligations include $757 million related to PPAs and $20 million for leases, a standard adjustment when calculating off-balance sheet liabilities.:

	2006 (with OBS)		2006 (without OBS)	
Short-term Debt	40,517	0.69%	40,517	0.80%
Long-term Debt	2,213,254	37.77%	2,213,254	43.54%
OBS Obligations	777,010	13.26%	-	-
Preferred Stock	33,497	0.57%	33,497	0.66%
Common Equity	2,795,551	47.71%	2,795,551	55.00%
Total Capital	5,859,828	100.00%	5,082,818	100.00%

Q. How does S&P's treatment of these contracts affect your financial policy?

A. Our financial policy must take S&P's adjustments into consideration if we are to achieve our target debt rating for PEF. This means that when developing target capital structure ratios, we must consider the impact of off-balance sheet items, in particular long-term power supply agreements due to their material impact on PEF's leverage.

If we were to ignore long-term purchase power contracts, as well as other off-balance sheet obligations, we would be setting target leverage ratios which would be inconsistent with S&P's view of our leverage.

Q. What leverage ratio is necessary for PEF to achieve a "single A" rating by S&P?

A. S&P considers PEF to have a business risk profile of "5". Their published guidelines state that adjusted leverage ratios for utilities with a business risk profile of "5" must range between 42% and 50%. While there are many factors taken into consideration by

S&P in determining the final credit rating, the leverage ratio is an important ratio. The mid-point of this range is 46% and would be the target leverage ratio for a company seeking to achieve a "single A" credit rating.

As shown above, the effect of off-balance sheet obligations changes PEF's projected 2006 leverage ratio from 45% (including preferred stock) to 52.29%, well above the mid-point of 46%.

Q. Has the Commission ever recognized the affect of off-balance sheet obligations like PPAs on a utility's capital structure?

A. Yes. Rule 25-22.081(7) requires utilities to include a discussion of the potential for increases or decreases in its cost of capital should a purchase power agreement with a non-utility generator be made.

In addition, the FPSC has recognized the impact of long-term PPAs when comparing the cost of building generation with the cost of executing a long-term power supply contract. [Order No. PSC-04-1168-FOF-EI, dated November 23, 2004.]

Lastly, FPSC has recognized the effects of long-term PPAs in Florida Power & Light's (FPL's) current revenue sharing agreement. Order No. PSC-02-0501-AS-EI, April 11, 2002, incorporates by reference the following provision from the Stipulation and Settlement approved by the FPSC in 1999, Order No. PSC-99-0519-AS-EI, March 17, 1999.

As stated in the Order:

> "FPL's adjusted equity ratio equals common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations. The amount used for off-balance sheet obligations will be calculated per the Standard & Poor's methodology as used in its August 1998 credit report."

Q. How should PEF's rates be adjusted for the effect of imputed debt associated with long-term PPAs?

A. PEF's weighted average cost of capital (WACC) should reflect the effect of imputed debt associated with long-term PPAs by recognizing on a proforma basis the amount of equity necessary to offset the effect of imputed debt. This approach is conceptually consistent with the recognition of PPAs in FP&L's capital structure calculation.

PEF's projected 2006 capital structure reflects a 55% common equity ratio, before taking long-term purchase power contracts into account. PEF would need $757 million of additional equity in its capital structure to maintain a 55% equity ratio after recognizing imputed debt associated with these contacts. PEF's WACC should be adjusted to properly reflect the additional equity necessary to offset the additional imputed debt. This adjustment is conceptually consistent with FPL's current revenue sharing agreement referred to above. The only difference is while PEF makes a proforma adjustment to the amount of equity in its capital structure for purposes of calculating its WACC, FPL makes a proforma adjustment to the amount of debt. However, the impact on WACC is the same.

Q. What is the benefit to the Company and the customer in recognizing the imputed debt associated with long-term PPAs?

A. Recognizing the imputed debt associated with long-term PPAs in this base rate proceeding would be a positive development for PEF's credit profile. I would expect S&P to view the Commission's recognition of these contracts as imputed debt and adjusting its WACC as enhancing to PEF's credit quality. Improving PEF's credit quality, and possibly its long-term credit rating, will reduce PEF's cost of borrowing as bond investors would consider PEF to have lower credit risk.

Q. What is the risk to the Company and customers if the Commission does not recognize any imputed debt associated with long-term PPAs?

A. The risk to the Company and customers is that PEF's credit quality will continue to suffer due to the lack of recognition of these contracts. As stated earlier, S&P considers the addition of long-term PPAs as increasing financial risk and makes adjustments to PEF's credit ratios to reflect this additional risk. The result of this is higher debt costs to PEF, weaker access to the capital markets, and an overall weaker credit profile, which puts PEF at greater risk of a downgrade. S&P currently has a negative outlook for PEF. An unfavorable outcome of PEF's base rate proceeding, including the treatment of long-term PPAs, would have a negative impact on PEF's credit profile and could result in a downgrade. This would further increase PEF's borrowing costs and further weaken its access to the capital markets.

Q. Has the FPSC ever made proforma adjustments to a utility's capital structure for ratemaking purposes?

A. Yes, PEF's existing revenue sharing agreement recognizes an adjustment for certain costs incurred during PEF's 1997 Crystal River nuclear outage. In this agreement, PEF's common equity is increased $109 million for purposes of calculating its return on equity. In addition, FPL's current revenue sharing agreement provides for a specific calculation of capital structure ratios which takes into account S&P's calculation of imputed debt associated with long-term power supply contracts.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF
JAVIER PORTUONDO

I. Introduction and Summary.

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is 100 Central Avenue, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Progress Energy Service Company, LLC, in the capacity of Director, Regulatory Services - Florida.

Q. What are the duties and responsibilities of your position?

A. As Director, Regulatory Services - Florida, I am responsible for all regulatory accounting and reporting activities of Progress Energy Florida ("PEF" or the "Company"). As it pertains to this proceeding, my responsibilities include the preparation of PEF's Minimum Filing Requirements submitted with its Petition and direct testimony on April 29, 2005, and the development of the adjustments to the Company's test year "per books" financial statements that produce the revenue requirements and revenue deficiency under current rates upon which its rate relief request is based.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of South Florida in 1992 with a Bachelor's Degree in Business Administration, majoring in Accounting. I began my employment with Florida Power Corporation in 1985. During my 19 years with Florida Power Corporation and PEF, I have held various staff accounting positions within Financial Services in such areas as: General Accounting, Tax Accounting, Property Plant & Depreciation Accounting, and Regulatory Accounting. In 1996, I became Manager, Regulatory Services, and in 2003 I was named Director, Regulatory Services - Florida.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is two-fold. First, I will address the development of PEF's Minimum Filing Requirements (MFRs) utilizing the "per books" financial data produced by the Company's 2005 and 2006 budget process described in Mr. Myers' testimony, including a discussion of the significant accounting changes since the Company's last base rate proceeding that have affected the financial data contained in the MFRs. Second, I will describe the various ratemaking adjustments made to the per books net operating income, rate base, and capital structure that are necessary for conformance with Commission-approved regulatory practices and policies, and to ensure that the test year results used to set rates in this proceeding properly reflect conditions that will exist while the new rates are in effect.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits which are attached to my direct testimony:

- Exhibit No. __ (JP-1), a list of Minimum Filing Requirements (MFRs) I sponsor or co-sponsor.
- Exhibit No. __ (JP-2), a summary table of the Company's 2006 test year results.
- Exhibit No. __ (JP-3), the revised methodology for allocating costs of Outage and Emergency ("O&E") activities between Operation and Maintenance ("O&M") and capital accounts.
- Exhibit No. __ (JP-4), a detailed calculation of the adjustment for depreciation expense.
- Exhibit No. __ (JP-5), an analysis of O&M expenses compared to the Commission O&M benchmark policy.
- Exhibit No. __ (JP-6), a schedule of post 9/11 security costs to be moved to base rates.
- Exhibit No. __ (JP-7), a schedule of the net cost savings from the Company's reorganization initiative.
- Exhibit No. __ (JP-8), a schedule of adjustments to annualize net test year benefits of the mobile meter reading program.
- Exhibit No. __ (JP-9), the Company's updated hurricane risk assessment study.
- Exhibit No. ___ (JP-10), a schedule of the types of costs charged to the Storm Damage Reserve.
- Exhibit No. __ (JP-11), reconciliation of test year capital and rate base.

These exhibits are true and accurate.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements (MFRs)?

A. Yes, I will sponsor or co-sponsor the MFR schedules listed in Exhibit No. __ (JP-1). These schedules are true and accurate, subject to their being adjusted in this proceeding. In addition, I will co-sponsor the following studies: The depreciation study included as Exhibit No. ____ (RHB-6) to the testimony of Mr. Robert Bazemore, Jr.; the nuclear decommissioning cost study included as Exhibit No. ____ (DEY-2) to the testimony of Mr. Dale E. Young; and the fossil plant dismantlement cost study included as Exhibit No. ____ (EMW-2) to the testimony of Mr. E. Michael Williams.

Q. How have you organized your testimony?

A. My testimony will begin by discussing the development of the per books data that serve as the basis for the Company's MFRs. The remainder of my testimony will be organized by the three components of the revenue requirements calculation; net operating income, rate base, and cost of capital. I will present each of these components on a per books basis, as derived from the Company's 2005 and 2006 budget process, and then describe the adjustments made to the per books data to arrive at the fully adjusted component used to calculate the Company's test year revenue requirements.

Q. What are the time periods covered by the MFRs that you will address in your testimony?

A. As a general rule, the individual MFR schedules provide financial data and other information for three annual periods: The "test year" is a forecasted calendar year

2006 and is based on the results of PEF's 2006 budget process; the "prior year" is calendar year 2005 and is based on the results of PEF's 2005 budget process; and the "historic year" is calendar year 2004 and is based on actual data from the Company's books and records. Certain MFR schedules also encompass additional periods such as, for example, 25 years of historic weather data to support "normal" weather figures used in the test year.

Q. Mr. Portuondo, would you please summarize your testimony?

A. Yes. When properly jurisdictionalized and adjusted, the Company's 2006 test year produces net operating income of $314.9 million and a rate base of $4640.5 million. The return requirement using a weighted cost of capital of 9.50%, which includes a rate of return on common equity of 12.8%, is $440.9 million. This produces a net operating income deficiency of $125.9 million which results in a revenue deficiency of $205.6 million as reflected on MFR A-1. This is the base rate increase requested by PEF in this proceeding, the first such increase sought by the Company since 1993. During this period of over twelve years the Company has not only avoided any increase in its base rates, but with the rate settlement implemented in 2002, PEF's current base rates are at the lowest level since 1983.

II. Development of MFRs.

Q. Please describe how PEF's MFRs were developed.

A. The starting point in the development of the MFRs was PEF's budget process for 2005 and 2006, which produced the 2005 budget and the 2006 forecast. The data from these two forward-looking periods, coupled with actual data from 2004, provide the Company's per books financial data that serves as the foundation of the MFRs.

The forecasted data for 2005 and 2006 were prepared in accordance with the same procedures and processes described in the testimony of Mr. Myers that are used by the Company to prepare its budgets for normal business purposes. The only change made to accommodate this proceeding was the inclusion of more detail in the second year of the budget process. In those instances where budget data required conversion into formats prescribed by the MFRs, such as specific FERC sub-accounts, the conversion was performed using the same standard allocation formulas routinely used to convert comparable actual data for regulatory accounting and reporting.

Q. What additional steps were taken in developing the MFRs from the per books figures provided by the Company's budget process?

A. To complete the development of the MFRs, a number of adjustments were made to the per books data to ensure the suitability of its use for ratemaking purposes. The unadjusted test year per books data taken directly from the results of PEF's budget process represents the Company's actual expectations for the operation of its business in 2006 at the time the data was prepared. However, because the budget process was designed for business purposes, the per books data derived from the budget process does not include the various refinements needed for ratemaking purposes. For these purposes, adjustments are required to provide consistency with the Commission's regulatory practices and to ensure that the data properly reflects the conditions that will exist when the rates set in this proceeding are in effect, as well as to reflect information that was not available until after the budget process had been completed. The adjustments made for these purposes to the PEF's per books net operating income, rate base, and capital structure are described in the next sections of my testimony.

Q. Have there been any significant accounting changes since the Company's last base rate proceeding that affect test year results shown in the MFRs?

A. Yes, there have been three significant accounting changes that warrant discussion. These accounting changes are (1) the adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations", (2) the requirement to recognize a Minimum Pension Liability in accordance with SFAS No. 87, "Employer's Accounting for Pensions" and the use of deferral accounting to offset this requirement for ratemaking purposes, and (3) the implementation of a revised accounting procedure for allocating the costs of PEF's Outage and Emergency activities between capital and expense accounts.

Q. Please describe the accounting change under SFAS No. 143 regarding asset retirement obligations.

A. Effective January 1, 2003, PEF adopted SFAS No. 143, which establishes accounting and disclosure requirements for retirement obligations associated with long-lived assets. SFAS 143 requires that the present value of the cost to retire assets for which PEF has a legal retirement obligation be recorded as a liability, and that an equivalent amount be added to the cost of the asset and depreciated over the period prior to its retirement. The liability is then accreted over the same period by applying an interest method of allocation to the liability.

Prior to SFAS No. 143, PEF recorded asset retirement obligations ("AROs"), specifically decommissioning of irradiated nuclear plant, based on amounts collected in rates. To ensure that the implementation of SFAS 143 is consistent with this prior treatment for ratemaking and surveillance purposes and does not have an effect on rate base or cost of service, PEF has made adjustments to its ARO accounts in accordance with Rule 25-14.014 adopted by the Commission in 2003 for this purpose. In addition, SFAS 143 effectively prohibits entities from recording asset removal costs that do not meet its definition of an asset retirement obligation. Therefore, for external reporting purposes, certain accumulated removal costs are reclassified as regulatory liabilities, since the costs are collected in PEF's approved rates. Such removal costs include interim cost of removal, fossil dismantlement, and removal of non-irradiated nuclear plant.

Q. **Please describe the accounting change under SFAS No. 87 regarding the recognition of a Minimum Pension Liability.**

A. The significant down-turn in the financial markets over the last several years resulted in wide-spread reductions in the value of pension plan assets, including components of PEF's pension plan. The reduction in the value of plan assets is compounded by an increase in the present value of the Company's future obligation to provide pension benefits earned by current employees due to a decrease in the discount rate used in the present value calculation. The compound effect of these events, in turn, triggered a provision of SFAS No. 87 that heretofore had never applied to the Company and that imposed an accounting treatment for pension costs that, unlike the normal requirements of SFAS 87, runs contrary to sound ratemaking practices. Under this newly invoked provision, when the value of a company's pension plan assets at any point in time is less than the present value of the pension obligation for benefits earned at the point in time, the company's pension obligation must recognize an additional liability, in the form of a Minimum Pension Liability ("MPL"), which is primarily offset by a charge to Accumulated Other Comprehensive Income, a component of equity. This current recognition of potential future obligation is contrary to the normal provisions of SFAS 87 and this Commission's ratemaking practice of recognizing the cost of employee pension benefits only as they are actually earned by employees over their years of service. To reverse the adverse ratemaking effect of the MPL that would result from the recognition of future pension costs in the test year, the Company has followed deferral accounting practices under SFAS No. 71 and created an offsetting regulatory asset, as authorized by Commission Order No. PSC-04-1216-PAA-EI in Docket No. 040816-EI.

Q. Please explain the revised accounting procedure for allocating the costs of Outage and Emergency activities between expense and capital accounts.

A. The revised procedure is based on a "best practices" recommendation prepared by an independent accounting firm hired by the Company to study the practices used in accounting for the costs of activities that incur both O&M and capital charges. The recommendation suggested specific revisions to PEF's procedures used to allocate costs of Outage and Emergency ("O&E") activities between O&M and capital accounts. The revised procedure will better distinguish between replacement costs, which are capitalized, and repair costs, which are expensed to O&M, and is expected to result in a higher level of O&E costs charged to expense. The charges to O&E accounts do not include the costs associated with major or named storms, which are tracked in separate accounts in accordance with guidelines from prior Commission proceedings. The revised methodology, which is summarized in my Exhibit No. ___ (JP-3), was adopted by the Company and implemented effective January 1, 2005. The effect of the revised procedure was not reflected in PEF's 2005-2006 budget process, which began well before the procedure was adopted, and has therefore been included as one of the test year adjustments discussed later in my testimony.

III. Net Operating Income.

Q. Please describe the development of the Company's net operating income contained in the MFRs for the 2006 test year.

A. The test year per books NOI was derived from PEF's Corporate Plan for 2005 - 2006 developed by the Company's budget process. The following is a description of the key inputs to the budget process.

- System revenues from sales of electric energy, including the derivation of deferred fuel revenue and unbilled revenues, were developed within the Corporate Model. Other operating revenues were developed by the Financial Planning Department with assistance from the Rate Department on certain revenue items. These revenues were determined through an analysis of historic trends, revised for changes associated with future events anticipated at the time the budget process took place.
- Fuel and purchased power expense was developed through PROMOD cost simulations and the Corporate Model.

- Non-fuel Operation and Maintenance (O&M) expenses were developed through the rigorous top-down, bottom-up budget process described in detail in the testimony of Mr. Myers.
- Depreciation expense was calculated using PEF's Commission-approved rates in Order No. PSC-98-1723-PAA-EI, Docket No. 971570-EI. The depreciation rates were applied monthly to the average depreciable electric plant in service balances, adjusted for additions and planned retirements. Decommissioning expense was determined based on the accrual to the reserve approved by the Commission in Order No. PSC-02-0055-PAA-EI, Docket No. 001835-EI, which was included as a separate component of depreciation expense. Fossil plant dismantlement expense was determined based on the accrual to the reserve approved by the Commission in Order No. PSC-01-2386-PAA-EI, Docket No. 010031-EI, which was included as a separate component of depreciation expense. As I discuss later in my testimony, these depreciation, dismantlement, and decommissioning expenses were adjusted for purposes of this proceeding based on updated cost studies included as exhibits to the testimony of Mr. Bazemore, Mr. Williams, and Mr. Young, respectively.
- Amortization expense was derived from amortizing investment in electric plant dedicated to Commission-approved energy conservation programs and intangible plant related to computer software over a five-year period.
- The details of developing Taxes Other than Income, including the type, amount and rate of each tax is provided in MFR Schedule C-20.
- Current and deferred income taxes were calculated based on the Company's operating and construction forecasts and the statutory tax rates in effect for both the federal and state jurisdictions.

- The Allowance for Funds Used During Construction (AFUDC) was calculated using the Company's Commission-approved annual rate of 7.81% in Order No. PSC-93-1785-FOF-EI, Docket No.930853-EI.
- Gross Receipts Taxes and Regulatory Assessment Fees were calculated based on the rates established by statute and the Commission, respectively.

Q. What is the basis for the adjustments made to PEF's per books NOI?

A. As I explained earlier, the budget-based per books NOI for the test year represents the Company's business-oriented expectations for 2006. As such, the test year data requires certain adjustments to accomplish the ratemaking purpose it is intended to serve in this proceeding. Like test year data in general, a number of these ratemaking adjustments, as well as adjustments for changes since the close of the budget process, have been made to the data comprising the Company's per books NOI. Below, I will describe these adjustments, first, on the basis of those made in recognition of Commission ratemaking policies or requirements, including several policies for which no adjustment was needed, and then I will describe the NOI adjustments deemed necessary by PEF to ensure that the test year is representative of the conditions that will exist when the rates set in this proceeding are in effect. In most cases the adjustments will be presented in a list format with a brief discussion. Other adjustments that require more elaboration will be addressed in response to separate questions.

Q. Please describe the adjustments to PEF's per books NOI that have been made to satisfy Commission ratemaking policies or requirements.

A. The following is a brief description of these Commission-based ratemaking adjustments to NOI. Some of the adjustments also have an effect on test year rate base and, therefore, will be included in the listing for rate base adjustments later in my testimony.

Fossil plant dismantlement expense. In recognition of the expiration of the 2002 Stipulation and Settlement approved by the Commission to resolve PEF's last base rate proceeding, Docket No. 000824-EI (the "Stipulation"), and its suspension of fossil dismantlement accruals, the Company commissioned a new fossil plant dismantlement cost study to determine the appropriate accrual level going forward. The cost study was performed by Sargent & Lundy and includes the Company's present value accrual calculations. It has been provided as an exhibit to Mr. William's testimony. The annual fossil dismantlement accrual beginning in 2006 determined by the study is $11.2 million (system) and $9.6 million (retail).

Nuclear decommissioning expense. The Stipulation also suspended the nuclear decommissioning accrual and its expiration at the end of 2005 caused the Company to commission a new cost study in order to determine the appropriate accrual level going forward. The cost study was performed by TLG and is provided as an exhibit to Mr. Young's testimony, along with the Company's present value accrual calculations. The study results indicate that the current balance in the Funded Nuclear Decommission Reserve, coupled with Forecasted Fund Earnings, will be sufficient to fund the future cost of decommissioning and, therefore, there is no need for a going-forward annual accrual to the reserve.

Depreciation expense. Similar to the situation with fossil dismantlement and nuclear decommissioning described above, the expiration of the provision in the

Stipulation allowing PEF to reduce the depreciation expense by $62.5 million made it necessary to commission a new study to determine the appropriate level of depreciation expense going forward. The new depreciation study, which is included as an exhibit to Mr. Bazemore's testimony, was performed by AUS and shows the need for a depreciation expense of $311.0 million (system) and $290.6 million (retail) beginning in 2006. This resulted in an adjustment to decrease test year per books depreciation expense by $54.4 million (system) and $48.8 million (retail), versus the assumed budget reduction of $62.5 million (retail). A more detailed calculation of this adjustment is included in my Exhibit No. __ (JP-4).

<u>Interest accrued on federal income tax deficiencies</u>. Consistent with the Commission's decision in the Company's last fully adjudicated base rate proceeding, Order No. PSC-92-1197-FOF-EI, Docket No. 910890-EI, an adjustment was made to test year expense for the accrual of interest to be paid on federal income tax deficiencies. In that rate case, the Commission stated:

> "In addressing interest on tax deficiencies, there are two things that we must consider. The first consideration is whether or not the company has demonstrated that its aggressive tax strategy (which results in tax deficiencies and the ensuing interest) has benefited the ratepayer such that the interest should be considered a cost of service component for 1992 and 1993. If the interest is considered a cost of service component, the second consideration is whether or not the requested three-year amortization period is reasonable.
>
> * * *
>
> "We believe that FPC's analysis was reasonable, and that the company has demonstrated that its tax strategies have benefited (sic) the ratepayers

through avoided cost-based external financing. This is consistent with our prior treatment of other utilities. Accordingly, we find that FPC's interest on tax deficiencies shall be appropriately included as a component of cost of service.

"That brings us to the question of amortization. We have decided to use a three year amortization period because that seems to be the midpoint of amortization periods that we have used for FPC."

Recoverable adjustment clause expenses. Expenses recoverable by PEF through its adjustment clauses (fuel and capacity cost recovery, energy conservation cost recovery, storm cost recovery clause (SCRC), and environmental cost recovery) have been removed from test year NOI. The removal of capital costs recovered though the adjustment clauses are addressed below in the portion of my testimony on adjustments to test year rate base.

With respect to environmental costs, the Company has not included any estimated costs to comply with new federal Clean Air Interstate Rule ("CAIR") issued by the U.S. Environmental Protection Agency on March 10, 2005. Given the uncertainty surrounding both the new regulations, which may or may not be challenged, and the current cost estimates for compliance, which are preliminary at best, the Company decided that costs of this type would be more appropriately recovered through the Environmental Clause than through base rates, despite the lack of Commission approval at this point. PEF intends to petition the Commission for clause cost recovery through a separate filing.

Franchise fee & gross receipts tax revenue and expense. The revenues and expenses have been eliminated from the income statement for ratemaking purposes consistent with Commission policies and orders. (See Order No. 11307, issued November 10, 1982 in Docket No. 820007-EU.)

Gain/Loss on sale of property. The gains or losses of utility property or property that was formerly utility property have been amortized above-the-line over a five-year period and considered part of determining net operating income consistent with Commission policies and orders. (See Order No. 11307, issued November 10, 1982 in Docket No. 820007-EU.)

Industry association and membership dues. Consistent with Commission policy, PEF has removed all EEI Media Communications Fund dues and one-third of EEI administrative dues, as well as all chamber of commerce dues.

Economic development expenses. An adjustment based on Commission Rule 25-6.0426, F.A.C., has been made for these expenses.

Sebring rider. Commission Order No. PSC-92-1468-FOF-EU, in Docket No. 920949-EU, which approved the Company's purchase of the Sebring Utilities Commission's electric system, provided that the amount of base purchase price in excess of the net book value and going concern value that is needed to retire the Sebring debt obligation will be collected only from customers located in Sebring's former service area in order that these costs will not be borne by PEF's general body of ratepayers. Therefore a ratemaking adjustment has been made to assure compliance with this provision of the Commission's order.

Rate case expenses. Based on long-standing Commission practice, the Company has amortized rate case expenses over a two-year period. MFR Schedule C-10 itemizes and details these expenses.

Q. Are there other Commission ratemaking policies that the Company applied to its test year NOI and found that an adjustment was not required for compliance?

A. Yes there are. After review, the Company determined that the Commission's ratemaking policies regarding fuel inventory levels and the benchmark for O&M expenses did not require an adjustment. Consideration of the policy on fuel inventory levels was rather straight-forward, since the Commission set out clear guidelines on this matter in Order No. 12645, in Docket No. 830001-EU. As the testimony of Mr. Dale Williams describes, the Company evaluated its test year coal and oil inventories against these guidelines for fuel inventory levels and found that the test year inventories satisfy the guidelines without the need for an adjustment.

Q. Please describe the application of the Commission's O&M benchmark policy to PEF's test year O&M expenses.

A. This Commission policy, often called the O&M benchmark test, is rather complex and number-intensive in the actual performance of the test. Before describing the data and numeric results that are presented in my Exhibit No. ___ (JP-5), I believe it would be helpful to address how the O&M benchmark test is structured generally and the objective of performing this exercise.

The benchmark test itself consists of two distinct but related parts. The first part is a comparison of PEF's test year O&M expenses, broken down into six functional areas, against O&M expenses from the 2002 test year in Company's last rate case, escalated over the intervening period by the CPI and, except for power plant O&M, customer growth. This allows those scrutinizing the Company's test year costs in this proceeding to see what the level of O&M expenses would have been within each functional area assuming that these expenses had experienced only the upward pressures of inflation, as measured by the CPI, and, except for power plant O&M, the rate of customer growth over the period since the Company's last base rate proceeding. This does not mean that the benchmark O&M expenses are somehow presumed to be what the Company's test year O&M should actually be. Rather, the benchmark provides the Commission with a useful analytical tool to identify and focus its attention on those specific areas of PEF's operation that have experienced proportionally higher O&M increases than other areas. The focus then shifts to the Company to justify the reasons that the CPI and customer growth are not representative of the upward cost pressures these areas have experienced. This is the second part of the benchmark test.

In this part of the test, PEF identifies individual expense items within the various functional areas that exceeded their own benchmark level for justifiable reasons, such as the need to perform new activities or increases in scope of existing activities compared to the last rate proceeding, or inflation rates greater than the benchmark escalators that have impacted a particular expense item. If the total of the benchmark variances for the individual expense items that have been justified in the second part of the test exceed the overall benchmark variance from the six functional areas determined in the first part of the test, then the Company has demonstrated that the overall variance is attributable to causes that the benchmark does not take into account, and has satisfied the Commission's O&M benchmark test.

Turning now to the results of the O&M benchmark test performed in this proceeding, the table in my Exhibit No. ___ (JP-5) shows that PEF's test year O&M exceeds the benchmark in the Production, Transmission, Distribution, and Administrative and General areas by $108.7 million, and that test year O&M for the

Customer Accounts, Customer Service, and Sales functional areas is below the benchmark by $25.6 million, for a net variance above the benchmark of $83.1 million. The Company's justification of the variance for individual cost components within each of the functional areas is provided in MFR Schedule C-41.

Q. Please describe the other ratemaking adjustments that you have made to PEF's per books NOI.

A. The following is a description of the NOI adjustments made in order for the test year to reflect conditions that will exist when the rates set in this proceeding are in effect, including adjustments for changes that have occurred after PEF's budget process was completed.

<u>Revised practice for charging Outage and Emergency activities</u>. The revised accounting procedure described earlier in my testimony was adopted to better distinguish between the costs of repair and replacement activities charged to Outage and Emergency ("O&E") accounts. Compared to the prior procedure reflected in the 2005-2006 budget process, the revised practice identifies a greater percentage of O&E charges as repair costs and a correspondingly lower percentage of replacement costs. The effect of this shift from capital to O&M charges is an adjustment to increase test year expense by approximately $34 million. The corresponding downward adjustment to test year rate base is addressed later in my testimony.

<u>Post-9/11 security costs</u>. In my testimony in the Docket No. 020001-EI, I made a commitment to the Commission on behalf of PEF that incremental security costs imposed on the Company in the wake of the 9/11 events and for which the Commission has allowed fuel clause recovery would be moved to base rates in

PEF's next rate case. The post 9-11 security costs included in the test year are based on the NRC rules and regulations that have been proffered for implementation as of December 31, 2005, and the regulations imposed under the Maritime Security Act of 2002. A schedule detailing these costs is contained in my Exhibit No. __ (JP-6). I would add that transferring these costs to base rates should in no away prejudice PEF from requesting clause recovery of incremental costs that the Company incurs as a result of new security requirements which may be imposed by federal or state laws or regulations that were not in effect at the time this case was initiated.

The Company's reorganization initiative. In keeping with the same ongoing effort to reduce costs through greater operating efficiencies that has allowed the Company to avoid increasing its base rate since 1993, PEF has undertaken a complete review of its organizational structure. This review focuses on all levels within the Company, from senior management down through the entire chain of command, in order to identify areas where further efficiencies could be achieved that will produce additional savings in the cost of operations. The initiative will be implemented throughout 2005 and into the beginning of 2006, including employee incentives for voluntary early retirement effective beginning in June of this year that will provide overall net wage and salary savings and mitigate the necessity of mandatory terminations for positions eliminated under the reorganization. The initial estimates of the cost savings, net of reorganization expenses, from this initiative were developed early this year and, therefore, were not available when the budget process for 2005 and 2006 was completed. As my Exhibit No. ___ (JP-7) shows in greater detail, net pre-tax cost savings of $19.5 million (system) and $17.6 million (retail) have been identified from the reorganization initiative for

2006 and are included as an adjustment to increase test year NOI. If any changes to these net cost savings, upward or downward, are identified as the initiative is implemented, the revision will be provided by supplemental filing.

PEF's mobile meter reading program. While not specifically a part of the reorganization initiative, PEF's mobile meter reading ("MMR") program's efficiency improvement and cost reduction objectives are the same. Under this program, the conventional electro-mechanical kilowatt-hour meters for all residential accounts, approximately 1.5 million, will be replaced with new solid state meters over an 18-month period beginning in April, 2005. The new meters will be equipped with radio transmitter modules capable of sending real-time metered data to a mobile receiver/collector unit in a vehicle traveling at 30 mph. A single meter reader equipped with one of these mobile units can read approximately 10,000 meters during an eight-hour shift, compared with an average of 400 meters per shift with manual reading. The MMR program was not included in PEF's budget process and it will not be fully implemented until part way through 2006. Therefore, the program's full O&M savings for a portion of the test year have been annualized over the entire test year for purposes of this pro forma NOI adjustment resulting in a reduction of test year expenses of approximately 13.9 million. A corresponding adjustment has also been made to the Company's test year rate base. The adjustment for the MMR Program includes a capital recovery schedule to amortize the net book value of the retired meters over a five-year period. My Exhibit No. ___ (JP-8) summarizes the adjustments made to reflect the MMR program's annualized net benefits in the test year.

The coal procurement consolidation project. The Company has recently begun implementation of another efficiency project to establish a single, centralized organization charged with the procurement and delivery of the coal requirements of its regulated production facilities, including PEF's Crystal River coal-fired plants. The new consolidated organization is intended to leverage fuel purchasing power, to optimize transportation contracts and assets, to improve coordination across functional groups, and to reduce costs while enhancing coal supply services to the Company's generating plants. Completion of the consolidation project is expected by the end of 2005. At that time the unit trains and related equipment presently owned or leased by Progress Fuels Corporation ("PFC") and used to supply the Crystal River site will be transferred to PEF. PFC's costs associated with this equipment is currently charged to PEF and recovered through its fuel clause, the majority of which will continue to be recovered in this manner after the transfer to PEF. However, approximately $1.8 million annually in related A&G expenses will no longer be eligible for fuel clause recovery after the transfer to PEF under existing Commission guidelines and have, therefore, been included as an adjustment to test year expense. In addition, a working capital adjustment related to this transfer from PFC to the Company will be addressed in the rate base section of my testimony below.

The domestic manufacturers' income tax deduction. This refers to the common name of a provision in the American Jobs Creation Act of 2004 that permits taxpayers to claim a federal income tax deduction for qualified income from domestic production activities, in PEF's case, the production of electric power. The deduction will be phased in effective with taxable years beginning in 2005 and will be fully effective with taxable years beginning in 2010. PEF has made a pro forma adjustment to reflect the estimated income tax benefit of this deduction in the test year. The estimate was determined in accordance with FAS

109-1, the recent guidance on tax accounting for the domestic manufacturers tax deduction issued by the Financial Accounting Standards Board ("FASB") on December 21, 2004. The adjustment reduces PEF's test year income tax expense by approximately $3.5 million (system).

Additional Transmission and Distribution ("T&D") expenditures. This adjustment to test year expense involves O&M expenses associated with the additional T&D activities described in the testimony of Company witnesses McDonald and DeSouza which were approved after completion of the 2005-2006 budget process. The corresponding capital costs associated with these T&D activities are included with the adjustments to rate base addressed later in my testimony.

Storm Damage Reserve accrual. Based on the results of an updated hurricane risk assessment study, PEF has increased the annual accrual to its Storm Damage Reserve to $50 million on a system basis, or $44 million more than the $6 million accrual approved by the Commission in Order No. PSC-94-0852-FOF-EI, Docket No. 940621-EI. The updated study, which is provided in my Exhibit No. ___ (JP-9), was commissioned by PEF in the wake of last year's hurricane season and was performed in accordance with Commission Order No. PSC-93-1522-FOF-EI.

Q. With respect to the Company's Storm Damage Reserve that will be funded by the increased accrual, has PEF addressed the types of costs that will be charged to the reserve in the event of future major storms?

A. Actually, the types of costs that are to be charged to the reserve were thoroughly addressed by the utilities and the Commission in the early to mid-1990s. PEF has confirmed to its satisfaction that these charges remain appropriate and, therefore, will continue adhering to this long-standing treatment of storm-related costs. A complete discussion of the background and continuing propriety of these charges to the reserve has been provided by the Company in Docket No. 041272-EI regarding PEF's petition to recover a portion of the costs it incurred for repair and restoration of service as a result of the 2004 hurricanes. The types of costs that will be charged to the Storm Damage Reserve are listed in my Exhibit No. ____ (JP-10).

IV. <u>Rate Base</u>.

Q. How was the Company's test year rate base contained in the MFRs developed?

A. As I described earlier, the development of PEF's rate base MFRs begins with the per books data derived from the 2005 - 2006 budget process, in combination with actual rate base investment though 2004 taken from the Company's books and records. Since the budget-based, per books rate base data represents information developed by the Company for its business purposes, certain adjustments to this data are required to develop test year data suitable for ratemaking purposes, as well as to update the rate base data for changes since completion of the budget process.

Q. Please describe PEF's adjustments to its per books rate base for the test year.

A. The following is a description of the Company's per books rate base adjustments. As I noted earlier, many of these adjustments are simply the corresponding entries to account for the rate base effect of adjustments to per books NOI described in that section of my testimony.

- Revised practice for charging Outage and Emergency activities. To recognize the corresponding effect of higher O&M charges for Outage and Emergency activities described in the adjustments to NOI, a reciprocal adjustment has been made to reduce capital charges to rate base for O&E activities under the Company's revised charging practice.

- Adjustments to the Accumulated Depreciation Reserve. It should be noted that the Company does have different practices for depreciation expense for its retail and wholesale jurisdictions. The Company keeps separate books and records for each jurisdiction and the Company's financial statements represent a blend of the 2 methods by applying the appropriate separation factors to each set of books. The Company's budget for 2005 and 2006 produces accumlated reserve for depreciation and depreciation expense on a blended basis. For the purpose of this proceeding however, we have prepared all the MFRs which present accumulated reserve for depreciation and depreciation expense using the retail jurisdiction depreciation method. These correspond to PEF's NOI adjustments to expense for fossil plant dismantlement, nuclear decommissioning, and depreciation based on the updated cost studies commissioned by PEF, which were discussed in the NOI section of my testimony.

- Recoverable adjustment clause costs. These adjustments also correspond to the NOI adjustments made to remove from the test year all costs that are recoverable through the adjustment clauses for fuel and capacity cost recovery, Energy Conservation Cost Recovery ("ECCR"), Storm Costs

Recovery Clause ("SCRC"), and Environmental Cost Recovery Clause ("ECRC"), which I described earlier.

- The Company's reorganization initiative. While the predominate effect of this initiative involves O&M expense, the corresponding rate base effect of capitalized labor costs has also been annualized through a test year adjustment.
- PEF's mobile meter reading program. The adjustment to annualize the net savings of the MMR program also includes a significant rate base component for the cost of the new solid state meters and mobile meter reading equipment, as well as a five-year amortization of the under depreciated balance, less salvage value, for the retired meters.
- Storm Damage Reserve. This adjustment is to the operating reserve in rate base working capital which is the counterpart to the NOI adjustment for the updated accrual.
- The coal procurement consolidation project. In addition to the shift of coal transportation-related A&G expense from fuel clause recovery to base rates described above, the consolidation project will result in title to the coal inventory in transit to the Crystal River plant site being held by PEF rather than PFC. As a result, the working capital requirements of this off-site inventory will also shift to base rates.
- Additional T&D expenditures. This adjustment corresponds to the NOI adjustment for the costs associated with the additional T&D activities described in the testimony of Company witnesses McDonald and DeSouza which were approved subsequent to the budget process.

- GridFlorida RTO deferred start-up costs. An adjustment has been made to remove these deferred costs from test year rate base, which have been reflected as a current-period expense for surveillance reporting purposes in prior years.
- Gain/Loss on sale of property. This adjustment corresponds to the NOI adjustment made for this purpose.
- Sebring rider. This adjustment corresponds to the NOI adjustment made for this purpose.

V. Capital Structure.

Q. Please describe the development of the Company's test year capital structure contained in the MFRs.

A. For the same reasons described above regarding NOI and rate base, several adjustments to PEF's per books capital structure are necessary for the test year to comply with the Commission's ratemaking policies. These include an adjustment to the equity component of PEF's capital structure to avoid an ongoing punitive effect of the costs the Company agreed to absorb in the settlement of an investigation into an unplanned outage at the Crystal River Unit 3 nuclear unit ("CR3"), an adjustment to the equity component of the Company's capital structure to recognize the treatment of its long-term purchase power agreements ("PPAs") by the agencies that rate the risk of PEF's debt securities, and an adjustment to directly assign commercial paper as the source of capital for funding the unrecovered fuel costs on PEF's balance sheet.

Q. Please explain the capital structure adjustment related to the CR3 outage settlement?

A. CR3 was placed into an extended cold shutdown in October 1996 to make modifications needed for NRC compliance purposes because of a remote safety contingency that had a probability of occurring less than once in 11.6 billion years. During the extended outage, the Commission initiated a prudence review concerning the outage. Shortly before the scheduled hearing in 1997, and after extensive prefiled testimony and discovery, the Company reached a settlement with the OPC and the other parties, which the Commission approved shortly thereafter by Order No. PSC-97-0840-S-EI in Docket No. 970261-EI. The settlement included a number of rate-related components and trade-offs, including the Company's agreement to absorb approximately $82 million in replacement fuel costs and $100 million in increased O&M expenses incurred as a result of the outage, which totaled approximately $109 million in after-tax losses.

Significantly, however, the settlement also authorized a ratemaking adjustment to the equity component of the Company's capital structure to ensure that the substantial adverse effect on its earnings in 1997 would not be compounded by an ongoing effect in future years. The extraordinary write-off of $109 million resulted in lower earnings per share in 1997 and reduced the Company's common equity balance. If no corresponding adjustment were made to the common equity balance in future years, the amount the Company could permissibly earn each subsequent year would have been severely reduced, thereby compounding the loss that it had agreed to absorb in 1997. To avoid such a long-lasting punitive effect, the settlement included and the Commission approved the

Company's right to make an offsetting adjustment to common equity when determining its earnings for regulatory purposes.

Q. Did the settlement or the Commission provide for a termination of this equity adjustment?

A. No, the settlement and the Commission's approval order provided an indefinite term for the adjustment. In fact, the Commission's order expressly stated that the stipulation was silent with respect to how long this adjustment will be made, and that "[t]he parties indicate it is contemplated within the (settlement) that this adjustment may continue beyond the four-year Amortization Period." During its Agenda Conference deliberations on this matter, the Company acknowledged and the Commission reflected in its order that the Commission would be entitled to review the issue in the Company's next rate case, whenever that might occur. Providing the Commission an opportunity for review, however, clearly does not mean that the adjustment would or should be terminated as an outcome of the next rate case, and the Company does not believe that it would be appropriate to do so as an outcome of this proceeding.

There might be a circumstance where termination of the adjustment would be a proper outcome if, for example, it appeared in the course of a rate case that the Company were able to achieve its desired capital structure without making this adjustment. But that is not the case here. To the contrary, even with the adjustment, PEF currently has a significantly lower percentage of equity in its capital structure than the other investor-owned utilities ("IOUs") in Florida. As a result, disallowing the adjustment would have the effect of unduly suppressing PEF's equity level in relation to its peer utilities. This would bring about exactly the result that the adjustment was developed to prevent, namely, penalizing the Company's future earnings because of its willingness to step up to the plate and absorb the immediate costs incurred during CR3's outage through compromise and settlement, despite the existence of the hotly disputed issues in that proceeding.

Q. What adjustment has been made to the Company's capital structure to recognize the rating agencies' treatment of PEF's obligations under its long-term PPAs?

A. As explained in the testimony of Mr. Sullivan, the Company must take into account the practice of rating agencies, particularly the dominant agency, Standard & Poor's, regarding the imputation of debt to a utility's capital structure based on the utility's off-balance sheet obligations under long-term purchased power agreements. The failure of a utility to offset this imputed debt with sufficient additional equity in its capital structure will inevitably result in a continued downward agency rating of future debt securities issued by the utility, for which the financial markets will require a higher return as compensation for the greater risk assigned by the rating agency to these securities. For a participant in a capital-intensive industry like PEF, the consequences of a higher cost of debt are significant and severe to both the utility and its customers. For this reason, PEF has made an adjustment to the equity component of its capital structure as a means to recognize this practical, real-world impact on the Company's debt/equity ratio for ratemaking purposes. The adjustment is shown in MFR Schedule D1A.

Q. Please describe the capital structure adjustment regarding the source of funds supporting PEF's unrecovered fuel cost balance.

A. Given the unique use of commercial paper to finance unrecovered fuel costs, it is prudent to account for these costs in PEF's capital structure through a direct assignment of commercial paper as the source of capital, rather than through a pro rata assignment of all sources of capital.

Q Why didn't you make a similar adjustment for the unrecovered balance resulting from PEF's other clauses?

A Given the nature of the expenses being recovered through the ECCR and ECRC, which include such cost as depreciation, return on investment, taxes, and O&M just to name a few, it would not be appropriate to direct assign the unrecovered balances from those adjustment clauses to commercial paper. These are the types of expenses that are more typically funded from all sources of capital.

Q. Please describe the capital structure adjustment for non-utility investment.

A. Consistent with past Commission practice, PEF's non-utility investment has been removed entirely from the equity component of its capital structure, rather than pro rata from all sources of capital.

Q. Are there any Commission ratemaking policies that the Company applied to its test year capital structure and found that an adjustment was not required for compliance?

A. Yes. PEF performed the Commission's ratemaking practice of reconciling test year capital structure with rate base. This reconciliation is summarized in Exhibit No. ___ (JP-11).

VI. **Conclusion.**

Q. Please summarize the calculation of PEF's test year revenue requirements based on the fully adjusted NOI, rate base, and capital structure set forth in the Company's MFRs and described in your testimony.

A. The fully adjusted test year shows that PEF requires retail revenues of $1.63 billion in order to cover operating expenses and produce a return of $440.9 million on a rate base of $4.64 billion at an average weighted cost of capital of 9.5 percent, including a rate of return on common equity of 12.8 percent. Mr. Slusser's testimony presents proposed rates and charges that will produce these revenue requirements from PEF's rates classes in proportion to the Company's costs to serve each of the classes.

Q. How do these revenue requirements compare with the test year revenues that would be produced under the Company's current rates?

A. Using the test year billing determinants provided in Mr. Slusser's testimony, PEF's current base rate would produce revenues of $1.43 billion. When compared to the Company's test year revenue requirements, current rates would result in a revenue deficiency of $205.6 million. This is the base rate increase requested by PEF's petition for rate relief and supported by the Company's witnesses and MFRs.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing prefiled testimony was assembled under my direct supervision.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 8th day of September, 2005.

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